A paper prepared for the

Economic Council of Canada

P.O. Box 527
Ottawa, Ontario
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Un document préparé pour le

Conseil économique du Canada

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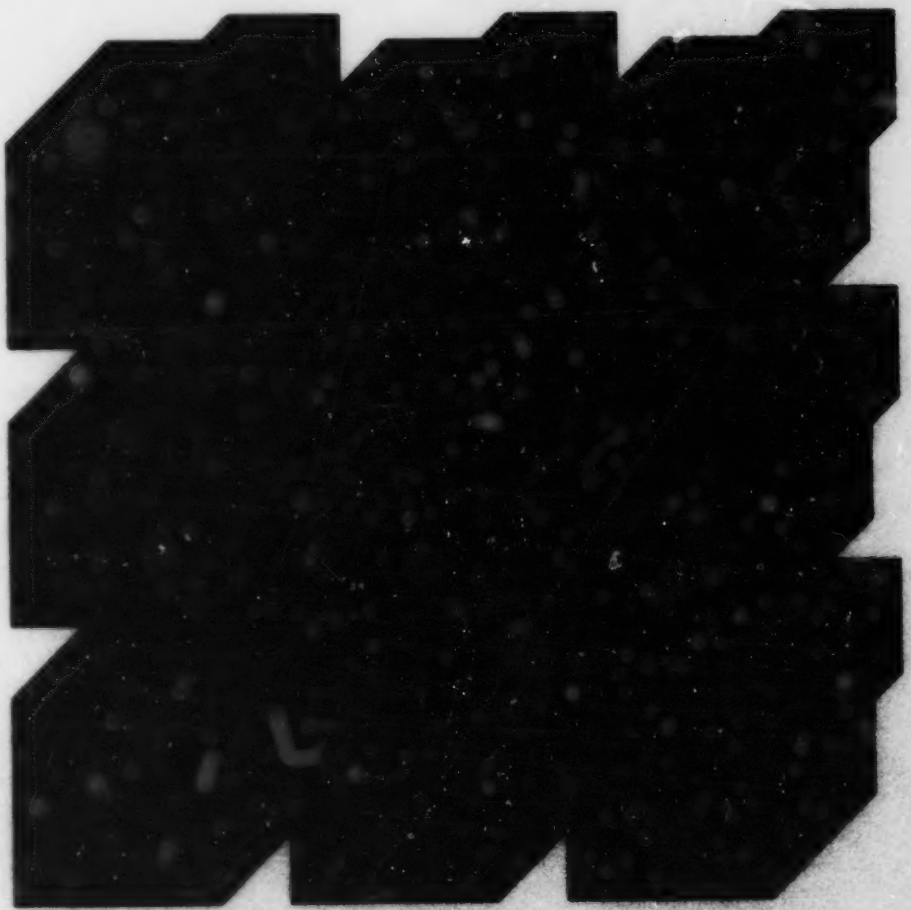
K1P 5V6



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DISCUSSION PAPER NO. 260

An Economic Analysis of Enhanced Oil Recovery in Conventional Light Oil Pools in Alberta

By Peter Eglington and
James A. Nugent

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ISSN-0225-8013

May 1984

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ACKNOWLEDGMENTS

The authors wish to thank Amoco Canada Petroleum Company Ltd. for their provision of the cost and production data, however, the results and conclusions are the responsibility of the authors alone and not of the company who has provided some of the input data. The price, inflation and cost of money assumptions are consistent with those being used in the Economic Council of Canada's Energy Group case studies. They have been neither suggested nor endorsed by Amoco.

The authors wish to thank Alan Short, an industry consultant working on the Economic Council of Canada's Energy Study, for his assistance and comments on earlier drafts of this study.

RÉCUPÉRATION DE PÉTROLE ASSISTÉE

1. Résumé

1.1 Introduction

Le présent résumé contient une analyse du degré de rentabilité de la récupération tertiaire de pétrole brut léger dans trois projets de récupération par injection de substances miscibles en Alberta, soit : la concession AB à Violet Grove dans le réservoir Pembina Cardium, l'unité 1 du bassin A dans le mésodévonien de Nipisi Gilwood, et la partie ouest de la zone de récupération par injection d'eau des bassins A et B du lac Beaver Hill dans le haut-dévonien de South Swan Hills.

Les trois projets diffèrent non seulement par leur taille et de leur emplacement respectifs, mais aussi par les caractéristiques géologiques des zones productrices, la superficie du projet de récupération tertiaire, la capacité de production des puits et leur compatibilité avec la méthode de récupération par injection de substances miscibles.

Le projet Violet Grove couvre une superficie de 640 acres (le champ Pembina s'étend sur un total de 475 000 acres. Le pétrole est tiré de la formation gréseuse de Pembina Cardium. La récupération

totale (primaire, secondaire et tertiaire) de la concession Violet Grove est évaluée à 60 % du gisement initial de 1,08 millions de mètres cubes. D'après les prévisions, la récupération tertiaire devrait s'élever à 15 % de la quantité initiale de pétrole sur place, ce qui équivaudrait à 0,27 millions de mètres cubes. La durée utile du projet serait de quarante ans.

Le projet Nipisi Gilwood couvre 3 840 acres, sur une superficie totale de 61 950 acres désignés pour la récupération par injection d'eau au bassin A du projet. Ici, le pétrole est tiré de la formation gréseuse mésodévonienne. La récupération totale (primaire, par injection d'eau et tertiaire) attendue de l'unité 1 de Nipisi Gilwood est évaluée à 71 % de la quantité initiale de pétrole sur place, soit 8,8 millions de mètres cubes. La récupération tertiaire s'élèverait à 22 % de cette quantité, soit l'équivalent de 2,73 millions de mètres cubes. La durée utile du projet serait de 20 ans.

Le projet de récupération par injection d'eau dans la partie ouest de Swan Hills couvre 11 000 acres. La production est tirée du haut-devonien aux bassins A et B du lac Beaver Hill qui sont des réservoirs de carbonate. La récupération totale (primaire, par injection d'eau et tertiaire) de la partie ouest soumise à l'injection d'eau est évaluée à 63 % de la quantité initiale de pétrole en place, soit à 25,4 millions de mètres cubes. La récupération tertiaire s'élèverait à 18 % de la quantité initiale de

pétrole sur place, ce qui équivaudrait à 7,25 millions de mètres cubes. La durée utile du projet serait de 20 ans.

Les trois projets ont tous déjà été soumis au procédé de récupération secondaire par injection d'eau. Les réserves restantes à être récupérées par injection d'eau, c'est-à-dire le pétrole pouvant être recouvré sans récupération tertiaire, s'élèvent à 9,25 millions de mètres cubes à Swan Hills, à 2,42 millions de mètres cubes à Nipisi Gilwood et à 0,22 million de mètres cubes à Violet Grove. Dans le procédé de récupération tertiaire par injection de solvants miscibles, on injecte dans un réservoir un fluide pouvant se dissoudre dans le pétrole afin de récupérer de la zone productrice le pétrole qui n'a pu être extrait lors du processus de récupération secondaire par injection d'eau.

Le procédé consiste à injecter un solvant d'hydrocarbure (des liquides de gaz naturel) et de l'eau en cycles alternatifs pendant 3 à 5 ans, et par la suite à injecter alternativement de l'eau et du gaz de purge (du gaz naturel) pendant un certain nombre d'années.

Ces dernières années, les gouvernements tant fédéral que provinciaux ont offert des stimulants visant à encourager la mise en chantier de projets de récupération assistée. Ces stimulants comprennent certaines réductions des redevances, une ristourne des redevances sur les solvants, des allégements de la taxe sur les recettes pétrolières et gazières et la classification du pétrole

extrait comme production de récupération assistée aux fins du prix de référence du nouveau pétrole.

Il s'agit dans le présent document d'étudier la rentabilité des projets de récupération assistée sous le régime fiscal actuel, compte tenu des stimulants spéciaux offerts pour ce genre de projets, en supposant un certain nombre d'hypothèses quant aux prix, aux proportions additionnelles récupérables et aux dispositions fiscales.

Les caractéristiques des réservoirs des trois projets sont présentées au tableau 1.1 et les chiffres au sujet de la production à la figure 1.1.

1.2 Résultats sur les flux monétaires

La rentabilité relative de chaque projet a été examinée à partir des recettes nettes actualisées et du coût réel d'approvisionnements, avec ou sans impôts et redevances (respectivement le scénario privé et le scénario social) pour diverses hypothèses quant aux coûts du capital et au partage des recettes entre les gouvernements fédéral et provinciaux et la compagnie. La comparaison ne porte pas uniquement sur la rentabilité respective des trois projets, mais aussi sur la façon dont risques et bénéfices sont partagés entre les participants dans le cas de diverses hypothèses quant aux prix et aux proportions des quantités récupérables.

Les recettes nettes actualisées avec ou sans impôts et redevances sont présentées au tableau 1.2. La valeur nette actualisée des parts échéant à la province, au gouvernement fédéral et à la compagnie est donnée au tableau 1.3. Les coûts sociaux et privés d'approvisionnement dans le cas du scénario de référence sont énumérés au tableau 1.4.

Les scénarios qui ne tiennent pas compte des impôts et des redevances ne représentent généralement pas le point de vue social, étant donné qu'ils englobent les composantes de la législation existante régissant les prix de l'ancien et du nouveau pétrole. Nous considérerons cependant que tous les scénarios faisant abstraction des impôts et des redevances sont des approximations raisonables du rendement social.

1.2.1 Le scénario de référence sans risque

Dans le scénario de référence sans risque, la rentabilité de chaque projet est calculée en supposant que le régime fiscal actuel appliqué aux projets de récupération assistée de pétrole léger en Alberta sera maintenu et que les prix réels du pétrole demeureront constants. Mentionnons que ce scénario est celui où le succès est assuré à 100 %.

Rentabilité : D'après les hypothèses du scénario de référence sans risque, South Swan Hills et l'unité I de Nipisi Gilwood sont deux projets très rentables aussi bien dans la perspective sociale que

privée, les bénéfices réalisés étant anormalement élevés, puisqu'ils atteignent 383 millions et 224 millions de dollars respectivement avant les impôts et redevances, et 58 millions et 38 millions respectivement après les impôts et redevances. Par ailleurs, Violet Grove, par comparaison aux deux premiers projets, n'est que marginalement rentable, ses recettes nettes actualisées ne s'élevant qu'à 8 millions de dollars avant les impôts et redevances et 0,4 million après les impôts et redevances au taux d'actualisation de 10 %. Par conséquent, le projet Violet Grove représenterait un risque beaucoup plus élevé que les deux premiers.

Le partage des recettes : La part fédérale des recettes nettes actualisées oscille entre 37 et 39 % dans le cas des trois projets au taux d'actualisation de 10 %, étant donné que la taxe sur les recettes pétrolières et gazières et les taux fédéraux de l'impôt fédéral sur le revenu sont fixes.

Le gouvernement provincial prélève de 45 à 46 % des bénéfices anormalement élevés, lesquels sont définis comme une rente économique, au taux réel d'actualisation de 10 %, dans le cas des projets les plus grands et les plus rentables, Swan Hills et Nipisi Gilwood. Contrairement à ce qu'on aurait cru, dans le cas du projet Violet Grove, d'une taille moindre et d'une rentabilité marginale, la part des recettes nettes échéant à la province est considérablement plus élevée, atteignant 58 % de la rente économique éventuelle. Une des raisons à cela est que la réduction des redevances prévue à l'article 4.2 des règlements de l'Alberta

Energy Ressources Conservation Board (AERCB) qui concerne les projets de récupération assistée est moins grande dans le cas des projets à faible productivité comme Violet Grove, que dans ceux d'une productivité élevée comme South Swan Hills et Nipisi Gilwood.

Globalement, les gouvernements s'approprient de 83 à 85 % des rentes économiques éventuelles des projets les plus rentables, c'est-à-dire Swan Hills et Nipisi, ne laissant que de 15 à 17 % des recettes nettes au secteur privé. Dans le cas du projet Violet Grove, dont la rentabilité est plus faible, les gouvernements extorquent à la compagnie quelque 95 % des bénéfices anormalement élevés et ne lui en laissent que 5 %.

Coûts d'approvisionnements et rentes économiques

Les coûts privés et sociaux des approvisionnements peuvent être définis comme les coûts réels d'approvisionnement du pétrole respectivement avant et après le paiement des impôts et des redevances.

La différence entre le coût social d'approvisionnement et le prix effectif au point d'extraction est une indication de la valeur de la rente économique à être partagée entre les gouvernements fédéral et provinciaux et la compagnie.

Les coûts des approvisionnements et la rente économique pour chacun des trois projets, au taux réel d'actualisation de 10 %, peuvent être résumés comme suit :

Coûts d'approvisionnement et rentes économiques
au taux d'actualisation de 10 %
en $ par mètre cube

	South Swan Hills	Unité 1 de Nipisi Gilwood	Concession AB de Violet Grove
Prix effectif au point d'extraction	271.22	229.69	267.14
Coût social d'approvisionnement	124.85	99.26	161.30
Rente économique totale	146.37	130.43	105.84
Coûts privés d'approvisionnements	160.29	206.71	261.24

Les coûts sociaux d'approvisionnement, lesquels s'échelonnent de 99 $ à 161 $ par mètre cubes, sont bien inférieurs aux prix effectifs au point d'extraction et par conséquent, tous les trois projets de récupération assistée sont économiquement rentables du point de vue social.

La décision d'une compagnie privée d'investir ou non dépend en partie de la différence entre le coût privé d'approvisionnement et le prix effectif au point d'extraction. Dans le scénario de référence sans risque, les projets Swan Hills et Nipisi Gilwood sont

tous deux très rentables, étant donné que leurs coûts privés d'approvisionnement sont considérablement moindres que leurs prix respectifs au point d'extraction. Par ailleurs, le coût privé des d'approvisionnements dans le cas du projet Violet Grove n'est inférieur au prix effectif au point d'extraction que par une marge de 5,90 $ le mètre cube. En conséquence, un projet socialement rentable comme celui-ci peut ne devenir que marginalement rentable pour le secteur privé à cause du lourd fardeau des redevances et des impôts qui s'élèvent à quelque 105,84 $ par mètre cube.

Bien que le projet de la concession de AB de Violet Grove soit en lui-même de taille relativement restreinte, il fait partie du champ Pembina, le plus grand champ de pétrole léger conventionnel dans l'Ouest du pays. Comme un grand nombre de projets de récupération assistée peuvent se retrouver dans cette catégorie marginale, les gouvernements devraient songer à accorder des stimulants additionnels aux projets de récupération assistée de pétrole s'ils désirent que de tels projets soient mis en chantier dans un proche avenir.

1.2.2 Effets de modifications du prix du pétrole

Une hausse annuelle de 5 % du prix réel du pétrole rend encore plus rentables les projets Swan Hills et Nipisi Gilwood. Toutefois, l'effet d'une augmentation du prix réel sur le rendement du projet Violet Grove, qui n'est que marginalement rentable, offre plus d'intérêt. Ce projet devient beaucoup plus attrayant à mesure que

les prix augmentent, et les recettes nettes actualisées (RNA) qu'il produit, ainsi que les taxes et les redevances, passent à presque 4 millions de dollars, à un taux réel d'actualisation de 10 %.

Les projets Swan Hills et Nipisi Gilwood peuvent aussi s'accommoder d'une diminution annuelle de 5 % du prix réel du pétrole, car leurs RNA après impôts et redevances tombent à environ 30 millions et 25 millions de dollars respectivement, à un taux d'actualisation de 10 %. Toutefois, du point de vue du secteur privé, le projet Violet Grove ne peut produire un taux réel de rendement de 10 % lorsque le prix réel baisse, comme le montre le tableau 1.2.

Une fois de plus, la part des recettes nettes allant au gouvernement fédéral se situe entre 37 et 39 %, peu importe que le prix réel du pétrole augmente ou diminue. Le projet Violet Grove fait exception à cette règle dans le scénario de prix décroissants, où la part du gouvernement fédéral tombe à 26 %. L'impôt fédéral sur le revenu est assez bien relié à la rente économique; il approche en effet de zéro lorsque la rente atteint sa limite. Après perception de la taxe sur les recettes pétrolières et gazières (TRPG), la rente économique qui reste est suffisamment près de zéro, de sorte que, lorsque le prix réel baisse, l'impôt fédéral sur le revenu à percevoir du projet Violet Grove est faible ou nul.

La part provinciale des recettes provenant des projets rentables (Swan Hills et Nipisi Gilwood), ne change pas beaucoup lorsque le

prix réel du pétrole augmente ou diminue. C'est donc dire que, dans ces circonstances, le système de redevances contribue efficacement à maintenir une part fixe des recettes, mais ne réussit pas à "capter" une plus forte proportion de la rente économique qui accompagne les augmentations de prix. En général, les politiques fédérales et provinciales ne sont pas assez souples dans le cas des projets très rentables.

Par ailleurs, la part des recettes nettes allant à la province productrice varie énormément pour les projets marginaux comme celui de Violet Grove, lorsque le prix du pétrole fluctue. Contrairement à ce qui se produirait si la politique fiscale était efficace, la part de la province tombe de 57 à 45 % lorsque la rentabilité s'accroît pour les entreprises privées, et elle atteint environ 175 % de la rente économique potentielle lorsque le prix du pétrole baisse. En dépit des réductions de redevances, la province reçoit plus de 100 % des recettes nettes, contraignants ainsi les entreprises privées à accepter une perte et à assumer les risques économiques lorsque les prix baissent.

Bien entendu, il faut modifier la politique fiscale existante - particulièrement la formule de calcul des redevances - pour qu'elle soit plus compatible avec la rente économique et avec un partage plus efficace des risques et des bénéfices reliés à l'incertitude en matière de prix.

1.2.3 Effets des variations sur la récupération additionnelle de pétrole

Un changement dans les volumes additionnels de pétrole récupérables reflète l'incertitude technologique et géologique découlant des diverses méthodes de récupération assistée du pétrole (RAP). Comme les coûts ne changent pas lorsqu'il se produit une modification du facteur de récupération tertiaire, les recettes nettes actualisées peuvent varier sensiblement.

En fait, leur valeur, après impôts et redevances, augmente beaucoup dans le cas des projets les plus importants et les plus rentables, tels ceux de Swan Hills et de Nipisi Gilwood. Toutefois, vu les faibles taux de production et la longue durée du projet Violet Grove - 40 ans comparativement à 20 ans pour les autres - une augmentation de 15 % des volumes additionnels de pétrole récupérables n'a que peu d'incidence économique sur les projets, les RNA après impôts n'augmentant que de 0.42 millions de dollars à 1.15 millions, compte tenu d'un taux d'actualisation de 10 %.

Les projets Swan Hills et Nipisi Gilwood restent encore rentables même si la récupération additionnelle est réduite de 15 %. À un taux d'actualisation de 10 %, les recettes nettes actualisées, après impôts et redevances, passent, pour Swan Hills, de 58 à 35 millions de dollars, et de 38 à 31 millions dans le cas du projet Nipisi Gilwood. Fait intéressant à noter, la diminution des recettes nettes actualisées du secteur privé est beaucoup plus forte dans le

premier cas que dans le second, parce que la proportion de la la production totale à laquelle s'applique le prix de référence du nouveau pétrole (PRNP), calculée par la "méthode du ratio fixe", est beaucoup plus élevée dans le cas du projet Swan Hills, soit de 0.453 comparativement à 0.106.

En valeurs relatives, l'effet d'une diminution de la récupération additionnelle de pétrole est plus important dans le cas du projet Violet Grove, car celui-ci passe alors de marginalement rentable à non rentable lorsque l'activité de récupération additionnelle diminue de 15 %.

Tout comme dans le cas des modifications du prix du pétrole, la part fédérale des recettes nettes est plutôt insensible à des variations de 36 à 38 % dans la récupération additionnelle de pétrole.

Pour le projet Nipisi Gilwood, la part des recettes nettes actualisées échéant à la province ne varie pas en fonction d'un changement dans les volumes additionnels récupérables; elle s'établit à 44 % s'il y a baisse et à 45 % s'il y a augmentation. Dans le cas du projet Swan Hills, la part de la province diminue si la récupération augmente et s'accroît si elle baisse (44 et 49 % respectivement), contrairement à ce qui serait une saine gestion des ressources. Il convient de faire remarquer que les parts des recettes nettes sont plus sensibles aux variations de la récupération additionnelle quant il s'agit du projet Swan Hills,

parce que la proportion de la production totale à laquelle est attribué le prix de référence du nouveau pétrole est beaucoup plus élevée que pour le projet Nipisi Gilwood.

Quant au projet Violet Grove, la part de la province fléchit à 52 % si la récupération augmente, et atteint 70 % si elle diminue. Ces constatations concordent avec les effets des variations de prix sur la part provinciale des recettes nettes dans le cas du projet Violet Grove.

Il est particulièrement intéressant de constater que la part de la province dans les recettes nettes s'accroît lorsque la récupération additionnelle décroît, et diminue à mesure qu'augmentent les facteurs de récupération tertiaire. En principe, le gouvernement devrait s'assurer une plus large part des rentes économiques éventuellement plus considérables et, au contraire, sa part devrait approcher zéro lorsqu'elles diminuent à presque rien. La sensibilité des parts de recettes nettes aux variations du volume de récupération additionnelle sont fonction à la fois de la proportion de la production totale, secondaire et tertiaire, à laquelle s'applique le PRNP, et de la rentabilité du projet avant impôts. Néanmoins, dans les trois cas analysés, la compagnie supporte la plus grande partie du fardeau de l'incertitude technologique et géologique. Par ailleurs, elle obtient une part des bénéfices découlant d'une augmentation imprévue de la récupération additionnelle. Ces possibilités prometteuses, pour le secteur privé, incitent fortement les compagnies à surestimer le facteur de

récupération assistée du pétrole (RAP) qu'elles prévoient ou à sous-estimer le niveau escompté de récupération primaire et secondaire. Malgré cette tendance, il n'est pas sûr que les compagnies profitent de cette inefficacité, à cause du système bien rodé d'audiences publiques auquel un projet éventuel de récupération assistée du pétrole est soumis par l'Alberta Energy Ressource Conservation Board avant que son exploitation soit autorisée.

Effets de la déréglementation des prix pétroliers

En situation de déréglementation du prix du pétrole, on attribue, par hypothèse, à la production le prix de référence du nouveau pétrole (PRNP) et on suppose que des redevances fondées sur ce prix sont payables. Une telle déréglementation a une incidence négative sur la rentabilité des projets de récupération assistée du pétrole, pour deux raisons.

1) Les incitations en matière de prix prévues actuellement par les politiques de prix relatives à l'ancien et au nouveau pétrole diparaissent.

2) Les taux de redevances diminuent, mais les sommes payables augmentent lorsque les redevances fondées sur le PRNP s'appliquent dans tous les cas.

Lorsque le prix du pétrole est déréglementé, les projets Swan Hills et Nipisi Gilwood demeurent quand même rentables. Toutefois, la déréglementation a des répercussions relativement plus importantes sur la rentabilité de celui de South Swan Hills, car ses recettes nettes actualisées tombent de 53 millions à 18 millions de dollars, comparativement à un fléchissement de 38 à 35 millions dans le cas du projet Nipisi Gilwood.

Quant à l'entreprise de Violet Grove, la déréglementation du prix du pétrole est suffisante pour la rendre non rentable, à un taux d'actualisation de 10 %. Cela est étonnant, car le projet demeure rentable du point de vue social, les recettes nettes actualisées avant impôts étant d'environ 7.75 millions de dollars dans le scénario de la déréglementation, comparativement à 8.39 millions dans le scénario de référence. Fait intéressant à noter, l'écart de 0,64 millions de dollars reflète vraiment l'effet, sur la rentabilité du projet, de l'élimination du stimulant en matière de prix, compte tenu d'un taux d'actualisation de 10 %.

La part fédérale des recettes nettes se maintient encore une fois entre 37 et 38 %.

La part provinciale des recettes nettes dans le cas des projets les plus rentables - c'est-à-dire ceux de Swan Hills et de Nipissi Gilwood - monte respectivement à 56 et 48 %.

D'autre part, pour le projet marginal de Violet Grove, elle augmente beaucoup lorsque le prix du pétrole est déréglementé, passant d'environ 58 à 64 %, et de marginale, la rentabilité du projet devient nulle.

Il est probable, cependant, que les taux de redevances sur le nouveau pétrole augmenteraient effectivement si le prix était déréglementé. Par conséquent, notre analyse de sensibilité dans les cas où des redevances fondées sur le PRNP sont payables pour tous les types de production, représente un scénario optimiste. Poussant notre analyse à l'extrême, nous avons déréglementé le prix du pétrole et appliqué à toute la production les taux de redevances relatifs à l'ancien pétrole. Comme le montre le tableau ci-dessous, les trois projets deviennent non rentables, à un taux d'actualisation de 10 %, dans l'hypothèse d'une déréglementation du prix du pétrole et si les taux de redevances relatifs à l'ancien pétrole s'appliquent à l'ensemble de la production.

Recettes nettes actualisées
à un taux de 10 %,
en dollars de 1983

South Swan Hills		Nipisi Gilwood Unité 1		Violet Grove Concession AB	
Sans impôts et redevances	Avec impôts et redevances	Sans impôts et redevances	Avec impôts et redevances	Sans impôts et redevances	Avec impôts et redevances
364,29	-3,24	261,45	-24,91	7,75	-0,82

À mesure que le prix intérieur du pétrole se rapprochera du prix mondial, les responsables des politiques devront prévoir d'autres moyens de favoriser la récupération assistée du pétrole (RAP) pour compenser l'élimination du stimulant en matière de prix et rajuster les redevances à la province, en vue de faire face plus efficacement aux variations de prix.

1.3 Résultats, conclusions et recommandations

1.3.1 Résultats

1. Selon les hypothèses non compromettantes du scénario de référence, les projets Swan Hills et Nipisi Gilwood sont très rentables, tandis que celui de Violet Grove ne l'est que marginalement.

2. Une augmentation du prix de 5 % par année contribue à sortir le projet Violet Grove de sa marginalité.

3. Si le prix du pétrole baisse de 5 % par année en termes réels, les projets Swan Hills et Nipisi Gilwood sont encore rentables, mais celui de Violet Grove ne l'est plus.

4. Une augmentation de 15 % du volume additionnel de pétrole récupérable n'a pas un effet suffisant sur l'exploitation du projet Violet Grove pour le tirer de sa marginalité.

5. Les projets Swan Hills et Nipisi Gilwood restent rentables, même si la récupération additionnelle diminue de 15 %, mais celui de Violet Grove devient marginal.

6. Pour le secteur privé, la déréglementation a une incidence négative plus considérable sur la rentabilité des projets de récupération assistée du pétrole. Même si ceux de Swan Hills et de Nipisi Gilwood demeurent rentables, le projet Violet Grove ne l'est plus lorsque le prix du pétrole est déréglementé.

7. La politique fédérale est trop rigide, en ce sens qu'elle maintient une part plus ou moins fixe des recettes nettes, quelles que soient les fluctuations dans les bénéfices anormalement élevé, en supposant, diverses hypothèses quant au prix et à la production.

8. La part des recettes nettes échéant à l'Alberta est beaucoup plus sensible aux variations des prix et des facteurs de

récupération dans le cas de projets marginalement économiques, comme celui de Violet Grove, que quand il s'agit de projets rentables, comme South Swan Hills et Nipisi Gilwood.

1.3.2 Conclusions et recommandations

À la lumière des résultats de nos analyses économiques des projets de récupération assistée de pétrole classique léger, il est possible de formuler certaines conclusions et recommandations.

1. Compte tenu de la structure de la taxe sur les recettes pétrolières et gazières (TRPG) - y compris les allègements possibles - ainsi que des impôts fédéral et provincial sur le revenu, la part des recettes allant au fédéral s'apparente à un pourcentage fixe de la rente économique potentielle.

2. Le stimulant que constituent les allégements fédéraux à la TRPG est inefficace dans le cas de ces projets de récupération parce que les faibles dépenses en immobilisations sont engagées la première année et que la rémunération du capital commence peu après. Le gouvernement devrait éliminer la TRPG dans le cas des projets marginaux ou leur accorder d'autres allégements en plus de celui qui se fonde sur le coût des immobilisations.

3. Malgré l'article 4.2 des règlements de AERCB, qui porte sur la réduction des redevances, la province obtient la plus grande

part des recettes et est donc mieux en mesure d'aider les projets marginaux.

4. La formule actuelle de calcul des redevances et les stimulants sous forme d'une réduction des redevances ne constitue pas une façon efficace de gérer la ressource. La formule de calcul des redevances devrait être modifiée pour mieux tenir compte des variations de la rente économique.

5. Actuellement, c'est le secteur privé qui supporte tous les risques économiques et technologiques. La province devrait assumer sa part de ces risques, par le biais du système de redevances, se réservant une plus large part des bénéfices si le rendement d'un projet se révèle plus élevé que prévu, mais une plus petite part des recettes si les activités de récupération ne répondent pas aux attentes.

6. À mesure que le prix intérieur du pétrole se rapprochera du prix mondial, les responsables des politiques devraient s'assurer que les projets RAP existants et éventuels seront protégés des effets négatifs de la déréglementation du prix du pétrole.

7. La province devrait s'assurer que toute modification de la formule actuelle de calcul des redevances supprime la tendance à surestimer le facteur de récupération tertiaire ou à sous-estimer les facteurs de récupération primaire et secondaire.

8. Le régime fiscal actuel ainsi que les stimulants à la récupération assistée du pétrole (RAP) contribuent beaucoup à favoriser les principaux projets RAP, comme ceux de Swan Hills et de Nipisi Gilwood, mais ils ont un effet presque négatif sur ceux qui sont marginaux, en ce sens que l'aide qu'apporte les stimulants est limitée. Au cours des années à venir, de plus en plus de projets de cette nature seront marginaux. Pour en favoriser la réalisation, les gouvernements devraient modifier les régimes d'impôts et de redevances afin d'assurer que les projets qui sont rentables au point de vue social le soient également dans l'optique du secteur privé.

1. SUMMARY

1.1 Introduction

This summary is a review of the economics of tertiary recovery of light crude oil in three hydrocarbon miscible flood projects in Alberta, namely Violet Grove AB Lease in the Pembina Cardium Reservoir, Nipisi Gilwood Unit 1 in the Nipisi Gilwood Middle Devonian A Pool, and the West Waterflood Area in the South Swan Hills Upper Devonian Beaver Hill Lake A and B pools.

The three projects vary not only in size and geographical location, but in the geology of the producing zones, the area of the project under tertiary recovery, the producibility of the wells and the response to miscible flood technology.

The Violet Grove project covers 640 acres (the total Pembina field covers 475,000 acres). Production is from the Pembina Cardium sandstone. Total recovery (primary, secondary and tertiary) from the Violet Grove lease is estimated to be 60 per cent of original oil in place amounting to 1.08 million cubic metres. Tertiary recovery is expected to account for 15 per cent of original oil in place equivalent to 0.27 million cubic metres. The economic life of the project is 40 years.

The Nipisi Gilwood project covers 3,840 acres (the total Nipisi Gilwood A Pool waterflood area is 61,950 acres). Production is

from the Middle Devonian Gilwood sandstone. Total recovery from the Nipisi Gilwood Unit 1 (primary, waterflood and tertiary) is estimated to be 71 per cent of original oil in place amounting to 8.8 million cubic metres. Tertiary recovery is expected to account for 22 per cent of original oil in place equivalent to 2.73 million cubic metres. The economic life of the project is 20 years.

The Swan Hills West Waterflood Area project covers 11,000 acres. Production is from the Upper Devonian Beaverhill Lake A and B pools which are carbonate reservoirs. Total recovery from the West Waterflood Area (primary, waterflood and tertiary) is estimated to be 63 per cent of original oil in place amounting to 25.4 million cubic metres. Tertiary recovery is expected to be 18 per cent of original oil in place equivalent to 7.25 million cubic metres. The economic life of the project is 20 years.

All three projects have previously been subjected to secondary recovery by waterflood. The remaining reserves to be produced from the waterflood, i.e., the production that would be recovered without tertiary recovery, is 9.25 million cubic metres from Swan Hills, 2.42 million cubic metres from Nipisi Gilwood and 0.22 million cubic metres from Violet Grove. In the tertiary recovery process the hydrocarbon solvent being miscible with oil is injected to recover additional oil in the producing zone that has not been removed in the secondary recovery flood.

The process consists of injecting a slug of hydrocarbon solvent (natural gas liquids) followed by water in alternating cycles for 3 to 5 years and then injecting water and chase gas (natural gas) in alternating cycles for a number of years.

In recent years both the federal and provincial governments have provided incentives to encourage the development of enhanced recovery projects. These incentives include royalty reductions, rebate on solvent royalty, PGRT relief and classification of production deemed to qualify as EOR production for the new oil reference price.

This paper examines the economics of enhanced recovery projects under the present fiscal regime including the special EOR incentives, with a number of assumptions relating to prices, incremental recovery fractions, and variations in tax provisions.

The reservoir properties for the three projects are presented in Table 1.1 and the production profiles in Figure 1.1.

1.2 Cash Flow Results

The economics of each of the projects will be compared by reviewing the net present value revenues and the real supply cost, both with (private case) and without (social case) taxes and royalties for various costs of capital as well as the revenue shares of the federal and provincial governments and the company.

The comparison will review not only the economic feasibility of the three projects but also how the risks and benefits are shared by the participants under various prices and recovery fractions.

The net present value revenues (NPVR) both with and without taxes and royalties are presented in Table 1.2. The net present value shares by province, federal government and company are given in Table 1.3. The social and private supply costs for the base case are listed in Table 1.4.

It should be noted that cases without taxes and royalties do not generally represent the social perspective because they include the old oil/new oil pricing components of existing legislation. However, we will consider all the cases without taxes and royalties to be reasonable approximations of the social return.

1.2.1 Unrisked Base Case

Under the unrisked base case the economics of each project are evaluated under the existing fiscal regime for light oil EOR projects in the province of Alberta and constant real oil prices. It should also be noted that this case represents the 100 per cent success case.

Profitability: Under the unrisked base case assumptions both South Swan Hills and Nipisi Gilwood Unit 1 are very profitable projects both in the social and private perspective realizing

above normal profits, of some $384 million and $224 million respectively before taxes and royalties and $58 million and $38 million respectively after taxes and royalties. On the other hand, Violet Grove, by comparison with Swan Hills and Nipisi Gilwood is a marginally economic project generating net present value revenues of some $8 million before taxes and royalties and $.4 million after taxes and royalties at a 10 per cent discount rate. As a consequence Violet Grove would be a much riskier project to develop than either of the other projects.

Revenue Sharing: The federal share of net present value revenues ranges between 37 and 39 per cent for all three projects at a 10 per cent discount rate due to the fixed rate structure of PGRT and federal income tax rates.

The provincial government takes between 45 and 46 per cent of above normal profits, defined as economic rent at a 10 per cent real discount rate, in the larger and more profitable projects, Swan Hills and Nipisi Gilwood. Surprisingly in the smaller and marginally economic project, Violet Grove, the province's net revenue share is considerably higher at 58 per cent of potential economic rent. One reason for this is that Section 4.2 EOR royalty relief is less effective on low productivity marginal projects like Violet Grove than it is on high productivity projects like South Swan Hills and Nipisi Gilwood.

Overall, the governments take 83-85 per cent of potential economic rents in the highly profitable projects, Swan Hills and Nipisi leaving 15-17 per cent of the net revenue pie for the private sector. In the low profitability project, Violet Grove, the governments gouge the company taking some 95 per cent of above normal profits leaving the company with only 5 per cent.

Supply Costs and Economic Rent: The private and social supply costs may be defined as the real resource supply costs with and without taxes and royalties respectively.

The difference between the social supply cost and the effective wellhead price is a measurement of the amount of economic rent to be shared by the federal and provincial governments and the company.

Supply costs and economic rent for each of the three projects at a 10 per cent real discount rate may be summarized as follows:

Supply Costs and Economic Rents
at a 10 per cent discount rate
in $ per cubic metre

	South Swan Hills	Nipisi Gilwood Unit 1	Violet Grove AB Lease
Effective Wellhead Price	271.22	229.69	267.14
Social Supply Cost	124.85	99.26	161.30
Total Economic Rent	146.37	130.43	105.84
Private Supply Cost	160.29	206.71	261.24

The social supply costs, ranging from $99 to $161 per cubic metre, are well below the effective wellhead prices and accordingly all three projects are economically viable enhanced recovery projects in the social perspective.

From a private perspective, the company's investment decision depends in part on the difference between the private supply cost and the effective wellhead price. For the unrisked base case both Swan Hills and Nipisi Gilwood are highly profitable since their private supply costs are considerably less than their respective wellhead prices. At the same time the private supply cost for Violet Grove is only $5.90 per cubic metre less than the effective wellhead price. The royalty and tax burden on this EOR project amounting to some $105.84 per cubic metre is large enough to result in a socially profitable project becoming only marginally economic for the private sector.

While the Violet Grove AB lease itself is a relatively small project it is part of the Pembina field, the largest conventional light oil field in Western Canada. As there are a great many potential EOR projects that may be in this marginal category, consideration of additional incentives will be necessary if the government wishes to encourage the development of EOR projects in the near future.

1.2.2 Effect of Changes in Oil Prices

A 5 per cent annual increase in real oil prices obviously improves the already profitable Swan Hills and Nipisi Gilwood projects. More interesting is the effect of increasing real prices on the marginally economic Violet Grove project. The Violet Grove project becomes much more attractive as prices increase and the NPVR with taxes and royalties increases to almost $4 million at a 10 per cent real discount rate.

Both Swan Hills and Nipisi Gilwood can also withstand a 5 per cent annual decrease in real oil prices with their respective NPVR after taxes and royalties falling to about $30 million and $25 million at a 10 per cent discount rate. However, the Violet Grove project is unable to generate a 10 per cent real rate of return in the private sector's viewpoint when real prices are decreasing as shown in Table 1.2.

Once again the federal government's share of the net revenue pie ranges between 37 and 39 per cent both with increasing and decreasing real prices. The exception is Violet Grove under the decreasing price scenario where the federal government's net revenue share falls to 26 per cent. Federal income taxes are reasonably well tuned with economic rents, approaching zero as rents approach the margin. After the PGRT is collected remaining economic rents are sufficiently close to zero such that little or no federal income taxes from the Violet Grove project are collected when real prices are decreasing.

The provincial share of revenues for the profitable projects, Swan Hills and Nipisi Gilwood do not change significantly when real oil prices increase and decrease. This suggests that the royalty system is effective in maintaining a fixed share of revenues in the event of rising or falling prices but is not effective in capturing a greater proportion of the economic rents accompanying higher prices. Overall both the federal and provincial policy is overly rigid where highly profitable projects are concerned.

On the other hand the province's net revenue share changes considerably for marginal projects like Violet Grove when oil prices fluctuate. Contrary to efficient tax policy the province's share falls from 57 per cent to 45 per cent when the private sector profitability improves and rises to some 175 per cent of potential economic rents when oil prices fall. Even with royalty

relief the province takes more than 100 per cent of net revenues forcing the private sector to incur a loss and bear the burden of economic risk when prices are decreasing.

Obviously existing fiscal policy, particularly the royalty formula, needs to be changed to become more in tune with economic rent and share the risks and benefits associated with price uncertainty in a more efficient manner.

1.2.3 Effects of Changes in Incremental Recovery

A change in incremental recovery represents the effect of technological and geological uncertainty associated with EOR schemes. Given that costs do not change in response to a change in the tertiary recovery factor, net present value revenues can change significantly.

Net present value revenues after taxes and royalties increase considerably for the larger more profitable projects, Swan Hills and Nipisi Gilwood. However, because of the low production rates and long project life of Violet Grove, 40 years compared to 20 years for the other projects, a 15 per cent increase in incremental recovery has little effect on the projects economics with after tax NPVR rising from $.42 million to $1.15 million at a 10 per cent discount rate.

The Swan Hills and Nipisi Gilwood projects are still profitable ventures if incremental recovery is reduced 15 per cent. At a 10 per cent discount rate the NPVR after taxes and royalties for Swan Hills falls from some $58 million to $35 million and for Nipisi Gilwood falls from $38 million to $31 million. It is interesting to note that the decrease in private sector NPVR is considerably larger for Swan Hills than it is for Nipisi Gilwood because the NORP fraction as calculated by the "fixed ratio method" is considerably larger in Swan Hills being .453 compared to .106.

In relative terms the impact of a decrease in incremental recovery is larger on Violet Grove since the project moves from being marginally economic to uneconomic when incremental recovery decreases by 15 per cent.

As was the case for changes in oil prices the federal government's net revenue share is fairly unresponsive to changes in incremental recovery ranging from 36-38 per cent.

The provincial share of net present value revenues is unresponsive to changes in incremental recovery in the Nipisi Gilwood project being 44 per cent for the decrease in recovery case and 45 per cent for the increase in recovery case. For Swan Hills the province's share decreases with more recovery and increases with less recovery (44 per cent and 49 per cent respectively) contrary to efficient resource management. It

should be noted that net revenue shares are more responsive to changes in incremental recovery in the Swan Hills project because the NORP fraction for Swan Hills is considerably higher than that for Nipisi Gilwood.

For Violet Grove the provincial share decreases to 52 per cent with increased recovery and increases to 70 per cent with decreased recovery. These observations are consistent with the effect of changing prices on the provincial share of Violet Grove net revenues.

It is remarkable that the province's net revenue share increases when incremental recovery decreases and decreases as tertiary recovery factors increase. As a general principle the government should take a larger share of larger potential economic rents and the converse, approaching zero as economic rents are minimized. The responsiveness of net revenue shares to changes in incremental recovery are a function of both the NORP fraction, i.e., the fraction of total production, secondary plus tertiary, receiving NORP, and the before tax profitability of the project. Regardless, in all three projects the company bears most of the burden of technological and geological uncertainty. On the other hand the company also shares the benefits resulting from an unexpected increase in incremental recovery. This private sector upside potential provides a strong incentive for companies to overstate the expected EOR recovery factor and/or understate expected primary and secondary recovery. Despite this incentive

which exists it is uncertain whether companies actually exploit this inefficiency because of the thorough public hearing process a potential EOR project is subjected to by the AERCB before permission to proceed with the proposed project is granted.

1.2.4 The Effect of Deregulation of Oil Prices

When oil prices are deregulated all production is assumed to receive NORP and pay NORP royalties. Deregulation of oil prices has a negative impact on the economics of EOR projects for two reasons.

1) The pricing incentives which currently exist under the old oil/new oil pricing policy are eliminated.

2) Royalty rates decrease but royalties payable increase when all oil pays NORP royalties.

Both South Swan Hills and Nipisi Gilwood remain profitable when oil prices are deregulated. However, deregulation of oil prices has a relatively larger impact on the economics of South Swan Hills with after tax NPVR falling from $58 million to $18 million compared to a fall from $38 million to $35 million for Nipisi Gilwood.

The impact of deregulation of oil prices on Violet Grove is large enough to make the project unprofitable at a 10 per cent discount rate. This is remarkable since the project remains

profitable in the social perspective with before tax NPVR of some $7.75 million in the deregulated case compared to $8.39 million in the unrisked base case. It is interesting to note that this $.64 million difference is a true measure of the impact of the elimination of the pricing incentive on the economics of the project at a 10 per cent discount rate.

Once again the federal government's net revenue shares remain in the 37-38 per cent range.

The provincial share of net revenues for the more profitable projects, Swan Hills and Nipisi Gilwood increase to 56 per cent and 48 per cent respectively.

The provincial share of the revenue pie for the marginal project, Violet Grove increases considerably when oil prices are deregulated. As the province's net revenue share increases from some 58 per cent to 64 per cent the project profitability moves out of the marginal range to become uneconomic.

It should be noted that it is probable that royalty rates on new oil would actually increase if prices were deregulated. Hence, our sensitivity analysis where all production pays NORP royalties is representative of an optimistic scenario. In the extreme case oil prices were deregulated and old oil royalty rates were applied to all production. As shown below all three projects become

uneconomic at a 10 per cent discount rate when oil prices are deregulated and all production pays old oil royalty rates.

Net Present Value Revenues
at a 10 per cent discount rate
in millions of 1983 dollars

South Swan Hills		Nipisi Gilwood Unit 1		Violet Grove AB Lease	
w/o taxes & royalties	with taxes & royalties	w/o taxes & royalties	with taxes & royalties	w/o taxes & royalties	with taxes & royalties
364.29	- 3.24	261.45	- 24.91	7.75	- 0.82

As domestic oil prices approach world oil market levels the policy makers need to provide further EOR incentives to compensate for the elimination of the existing pricing incentive and adjust provincial royalties to respond to price changes in a more efficient manner.

1.3 Results, Conclusions and Recommendations

1.3.1 Results

1. Under the unrisked base case conditions Swan Hills and Nipisi Gilwood are highly profitable whereas Violet Grove is only marginally economic.

2. Increasing prices by 5 per cent per year moves Violet Grove out of the marginal category.

3. Swan Hills and Nipisi Gilwood are still profitable if prices decrease 5 per cent annually in real terms but Violet Grove becomes uneconomic.

4. A 15 per cent increase in incremental recovery does not have a sufficiently large enough impact on Violet Grove to move it out of the marginal category.

5. Swan Hills and Nipisi Gilwood are still profitable if incremental recovery decreases by 15 per cent but Violet Grove becomes marginally uneconomic.

6. Deregulation has a large negative impact on the economics of EOR projects in the private sector's viewpoint. Although Swan Hills and Nipisi Gilwood remain profitable, Violet Grove becomes uneconomic when oil prices are deregulated.

7. Federal policy is overly rigid maintaining a relatively fixed share of net revenues regardless of changes in above normal profits which result under the various pricing and production assumptions.

8. Alberta's share of net revenues is much more responsive to changes in prices and recovery factors in marginally economic projects like Violet Grove, compared to profitable projects like South Swan Hills and Nipisi Gilwood.

1.3.2 Conclusions and Recommendations

In view of the findings of our economic analyses of conventional light oil EOR projects a number of conclusions and recommendations can be made.

1. The structure of PGRT with PGRT relief and federal and provincial income taxes results in the federal share being close to a fixed percentage of potential economic rent.

2. The federal government's PGRT relief incentive is ineffective in these projects because the low capital costs are incurred in the first year of project life and payout occurs early in the project life. The government should eliminate PGRT for marginal projects or provide further PGRT relief in addition to that based on capital costs.

3. Despite the Section 4.2 royalty relief the province receives the largest slice of the revenue pie and is thus in the best position to provide further incentives for marginal projects.

4. The existing royalty formula and royalty relief incentives do not efficiently manage the resource. The royalty formula should be ammended to respond more effectively to changes in economic rent.

5. At present the private sector bears the burden of both economic and technological risk. The province should participate in these risks through the royalty system taking a larger share of the benefits if returns are greater than expected and a smaller share of the revenues if recovery is on the downside of expectations.

6. As domestic oil prices move towards world oil market levels policy makers should make sure that existing and potential EOR projects are cushioned from the negative effects of deregulation of oil prices.

7. The province should insure that any changes in the existing royalty formula eliminates the incentive to overstate the tertiary recovery factor and/or understate the primary and secondary recovery factors.

8. The existing fiscal regime and current EOR incentives are very supportive of major EOR prospects such as Swan Hills and Nipisi Gilwood but have almost a negative approach to marginal EOR projects in that the EOR relief is constrained. In the years to come more and more potential EOR projects will be of a marginal nature. To encourage development of these projects the governments should amend the tax and royalty systems to ensure that projects that are profitable in the social perspective are also profitable in the private perspective.

2. CASE STUDIES

2.1 Introduction

It is important to note that the existing fiscal regime for EOR projects makes it impossible to model the incremental economics of an EOR project without considering the economics of the total production from the field, with the EOR component. Accordingly both the economics of the total project area, which includes the miscible flood, and a "base case project" without the miscible flood are modelled separately for each project.[1] The economics of the incremental production, resulting from the tertiary miscible flood in each case, are given by the difference between the total project economics and the base case project economics. Since this paper focusses on the economics of the tertiary miscible flood in each case under various pricing and recovery scenarios only the economics of this EOR project (i.e. incremental production economics) will be discussed in the text. However, net present value revenue, revenue shares and real supply cost calculations for the total project and the base case project may be found in Appendix C.

The results for incremental production due to EOR are reported for all sensitivity scenarios, and it should be noted that net present value revenues include net revenue generated by the production of byproducts as well as the production of oil. The production profiles for oil and associated byproducts for both the

base case and the total project are included in Appendix B. All results are reported in constant 1983 dollars. An explanation of the sensitivity scenarios is also given in Appendix A.

2.2 Operating and Capital Costs

The operating costs associated with these EOR projects are relatively large because of the substantial injection requirements. However because most of the required wells are already in place capital expenditures are minimal and are incurred in year 1 of the project life in all three projects.

2.3 Fiscal Regime

The fiscal regime used to analyze these EOR projects is that which currently applies to EOR projects in the province of Alberta. A summary of the current fiscal regime which applies to conventional oil and EOR projects is given in Appendix A.

2.4 EOR Incentives

In recent years both the federal and provincial governments have provided assistance in the form of tax and royalty relief in an effort to encourage EOR projects.

Although the incentives have generally been successful there still remain more potential EOR projects that have not been

developed than EOR projects that have been put in place. In this paper an attempt will be made to examine the effect of the various EOR incentives on the economics of the project, under alternative pricing and recovery scenarios.

The most significant EOR incentives to be announced in recent years are:

1) EOR royalty deductions provided under Section 4.2 of the Alberta Petroleum Royalty Regulations which were amended by the Alberta government in 1982.

2) NGL rebate provided under Section 4(3) of the Alberta Petroleum Royalty Regulations,

3) PGRT Relief announced by the Federal Government in the spring of 1983 and,

4) the 1981 Federal/Alberta Pricing Agreement which allows all incremental production from EOR projects to qualify for NORP.

The oil production which receives NORP in conjunction with an EOR project is determined by the fraction of additional reserves from EOR to total reserves, applied to the field's total production as soon as the EOR project has been recognized by the AERCB. In this arrangement it is crucial to note that NORP does

not just apply to the actual incremental EOR production. In fact, in a lease where the EOR production is relatively small and slow to come on stream almost all the production in the near future which would receive NORP would not be EOR production. Although this method allows some current production to receive NORP alternative schemes for defining EOR production are fraught with bureaucratic risks. In general, this method of determining EOR production is considered to be a much needed incentive for EOR projects. This method of deeming production as being associated with the EOR scheme is generally called the fixed ratio method. The NORP fraction is defined as follows.[2]

NORP Fraction = Total Recovery including EOR - Remaining Waterflood Recovery/ Total Recovery including EOR

= Incremental Reserves due to EOR/ Total Remaining Recoverable Reserves (including EOR)

2.5 Risk

The three elements of risk including technological risk, economic risk and political risk all apply to EOR projects but perhaps the two of most concern are:

i) the technological risk resulting from the uncertainty associated with the engineering and geology of each pool, and relative inexperience in EOR project development, and

ii) the economic risk resulting from the generally high operating costs of EOR projects and the uncertainty of oil prices.

The stability and design of fiscal regimes is another economic concern which overlaps with political risk. In recent years various EOR technologies and operating techniques have been improved and the economic environment associated with EOR projects has become more favourable. However, the fact that many potential EOR projects remain undeveloped suggests that there is still a high degree of technical and economic risk associated with them.

A detailed explanation with an example calculation showing the effects of the various EOR incentives is provided in Appendix D. Many of the EOR incentives built into the existing fiscal regime are designed to lower the risk involved in an EOR project, by lowering the up-front costs of a project. For example, under Section 4.2 of the Petroleum Royalty Regulations the Alberta government provides for reducing the royalties payable when a project is in the injection phase. However, EOR projects are only eligible for royalty relief under Section 4.2 if:

> "the estimated royalty revenues accruing to the Crown under the scheme (are) equal to or greater than the royalty revenues that would have accrued if the scheme had not proceeded on a discounted basis. (The discount rate to be used is 10 per cent)"[3]

Thus even though the province is willing to help reduce the economic risk associated with an EOR project by providing early royalty deductions, the province has attempted to assure itself that it does not reduce the present value of its eventual royalty take. This provision, however, does expose the government to more risk because its royalties are taken later.

Section 4(3) of the Alberta Petroleum Royalty Regulations provides a royalty deduction in respect of natural gas liquids which are injected into a well. The reduction is equal to the lesser of the value of NGL's injected and 5 per cent of the royalty payable on total production.[4]

The Federal Government's PGRT Relief only benefits projects in which payout is delayed and projects with high capital costs. For projects like South Swan Hills PGRT relief is minimal. The EOR project was initiated while the unit was still producing substantial amounts (volumes) of oil. As a result, payout occurs in the first year of production. Furthermore, much of the capital equipment required for an EOR project was already in place. Thus the capital costs required to start the EOR project were small and were all incurred in the first year of project life. Under these circumstances PGRT relief provides essentially no incentive to develop the project.

3. CASE 1 - SOUTH SWAN HILLS

3.1 Introduction

This section examines the hydrocarbon miscible flood in the West Waterflood area of the South Swan Hills unitized field under various conditions of price, incremental recovery fractions and cost of money. The major objective of this analysis is to look at the effect of various price assumptions and incremental recovery fractions on the economics of this EOR project. This will be done by estimating the net present value revenues and real supply costs, both with (private case) and without (social case) taxes and royalties for various costs of money. The analysis will also look at the respective revenue shares of the federal and provincial governments and the company.

The paper proceeds with a brief description of the South Swan Hills unit. We then discuss the effect of variations in oil prices and incremental recovery fractions on the economics of the South Swan Hills project.

3.2 The South Swan Hills Unit[5]

3.2.1 Geology and Location

South Swan Hills is located approximately 120 miles northwest of Edmonton, Alberta.

The Swan Hills reserves belong to the Beaverhill Lake formation which is a carbonate reef of Upper Devonian age. The Beaverhill Lake reef is divided into five geologic zones. In the West Waterflood area only zones 1 and 2 are productive and will be miscibly flooded.

3.2.2 Background

The South Swan Hills field was discovered in 1959, and Unitization was completed in October 1963 with Amoco, the main partner in the field, being the operator. Amoco's interest in the field is 44.07 per cent. Original oil-in-place (OOIP) is estimated by the AERCB to be 142.8 million cubic metres.

The South Swan Hills Unit is divided into three areas: the East Platform Area; the secondary miscible flood area; and the West Waterflood Area, as shown in Figure 3.1. In 1963 water injection began in the unit with an estimated recovery fraction of 45 per cent OOIP. In 1973 a miscible flood was installed in the central portion of the unit. This increased the estimated recovery fraction for the miscible flood area to 65 per cent OOIP. Water injection began in the East Platform in 1976. Finally, in 1982 the West Waterflood Area was converted to a miscible flood.

Presently in the entire South Swan Hills Unit there are 190 producing wells, 2 observation wells, 3 suspended wells and 63 injection wells. There are also three major facilities in

operation which provide injection fluids. They are the Freeman Lake Water Plant which was built in 1963, the Miscible Flood Plant which was built in 1973 and Battery #9 - Salt Water Plant #2 which was completed in July 1983.

Total production to date for the entire South Swan Hills Unit is 47 million cubic metres. Thus there still remains an estimated 81.8 million cubic metres of oil-in-place.

3.2.3 The West Waterflood Area Miscible Flood Project

The focus of this paper is the hydrocarbon miscible flood in the West Waterflood Area which was started in September 1982. This project is spread out over an area of 4,400 hectares and consists of fourteen inverted 9-spot patterns with 160 acre well spacing. Project life is estimated to be 20 years (i.e., 1983-2002). The miscible flood consists of 165 producer wells and 14 injection wells, of which seven were existing water injectors and seven were converted from producers.

A 10.3 per cent hydrocarbon pore volume (HCPV) solvent slug will be injected with water in alternating cycles. This will be followed by a 32.2 per cent HCPV chase gas slug injected in alternating cycles with water. Solvent injection will continue until 1986. Water and chase gas injection will continue until 1999. All water used for injection will be produced water. The

major source of the NGL required for the HCPV solvent will be the Mitswan system and the gas will come from the Judy Creek plant.

Original oil-in-place (OOIP) is estimated to be 40.7 million cubic metres in the West Waterflood Area and the estimated recovery fraction is 34 per cent. Current production from the unit is some 6.02 thousand cubic metres per day and the peak incremental production from the tertiary miscible flood is 1.16 thousand cubic metres per day for the total project as shown in Appendix C.

3.3 Cash Flow Results and Sensitivities

3.3.1 Net Present Value Revenues

Analysis of Net Present Value Revenues (NPVR), shown in Table 3.1, is undertaken at various discount rates, under various scenarios of price and oil recovery, and with full taxes and royalties versus no taxes and royalties. It should be noted that the cases without taxes and royalties do not generally represent the social perspective (as opposed to the private perspective) because they include the old oil/new oil pricing components of existing legislation, although not the taxes and royalties.

Only the case with oil prices deregulated, without taxes and royalties, represents the true social perspective. However, the differential pricing effect upon this particular project is found

to be small and consequently all the cases without taxes and royalties may be viewed as approximations of the social return.

Unrisked Base Case - Constant Real Prices

Net present value revenues are positive both with and without taxes and royalties considered over all discount rates. Thus, the hydrocarbon miscible flood in the West Waterflood area of the South Swan Hills Unit is economically viable under the unrisked base case. Further analysis indicates that the project realizes a real rate of return that is greater than 40 per cent assuming 100 per cent success.

Increasing Real Prices

Under the increasing real price case both the NORP and Old Oil price were increased annually by 5 per cent real.

When real prices increase the net present value revenues generated both with and without taxes and royalties are higher than the unrisked base case, by close to 79 per cent for the private sector and about 77 per cent for governments, at a 10 per cent discount rate. Under the existing fiscal regime federal and provincial tax rates and the PGRT rate would not change. However, royalty rates are a function of both production and prices. As a result, under an increasing real price scenario royalties payable increase.

Despite this however the shares of NPVR going to each government and the private sector remain virtually unchanged.

Decreasing Real Prices

Under the decreasing real price scenario both the NORP and old oil price were decreased annually by 5 per cent in real terms. As would be expected net present value revenues both with and without taxes and royalties are lower than the unrisked base case, by about 47 per cent for the private sector and some 45 per cent for the government, at a 10 per cent discount rate. It is remarkable that the private sector share in NPVR declines slightly. Once again federal and provincial tax rates are insensitive to the change in real oil prices while the royalty rate shows some downward responsiveness to the decrease in oil prices. The decrease in royalties payable is small relative to the change in the price of oil. Overall the fiscal regime appears unresponsive to change in private sector profitability from price changes, and is somewhat perverse in that it takes a larger share of net revenues for government as private profitability is reduced.

Oil Prices Deregulated

An interesting scenario to analyze is the deregulation of oil prices in which all oil receives NORP regardless of whether it is old oil or EOR "new oil".

The "Memorandum of Agreement" between the Federal Government and the Government of Alberta states:[6]

> "incremental oil", as determined by the fixed ratio method, recovered from pools or portions of pools subject to enhanced recovery schemes (other than waterflood schemes) commencing operation after December 31, 1980; qualifies for the New Oil Reference Price (NORP).

It should also be noted that for this project all primary and secondary production receives the old oil price. However, in general any oil discovered after 1973 qualifies for NORP.

Under a case of price deregulation where all oil production receives NORP, the incremental pricing incentives which currently exist for EOR projects are eliminated. As shown in Table 3.1, deregulation of oil prices has a significant negative impact on the incremental economics of the EOR project reducing the private NPVR from about $58 million to some $18 million, a 69 per cent decrease, at the 10 per cent discount rate. This problem is likely to haunt the policy makers as they try to move domestic prices more in line with market forces.

Net present value revenues without taxes and royalties are slightly less under the deregulation case than under the unrisked base case. This small decrease stems from the pricing effect on production artificially receiving NORP under the fixed ratio method. A summary of the various components included in a net

present value revenue calculation at a 10 per cent real discount rate is shown in Table 3.2.

Unquestionably deregulation of oil prices has a negative impact on the incremental economics of the EOR project. This means that further changes in the fiscal regime are virtually certain to be required as domestic oil prices are rationalized in the next few years, making for an unstable fiscal climate.

Increase in Incremental Recovery

As in the other sensitivities Federal and provincial tax rates are unresponsive to the increase in incremental recovery but royalty rates increase somewhat because royalties are a function of production and price.

The private sector benefits proportionately more than government, receiving an increase of about 66 per cent in NPVR as a result of the 15 per cent increase in recovery, at the 10 per cent discount rate. Private sector profitability is extremely sensitive to the recovery factor providing a strong incentive for efficient management of the project. A note of caution should also be sounded because this result is conditioned by the existing fiscal regime because it relies on the old oil/new oil distinction and the fixed ratio method. There is therefore a strong incentive for companies to overstate the expected EOR recovery factor and/or understate the expected primary and secondary recovery. However,

the AERCB eliminates this incentive in the Public Hearing process which is required before a project is approved.

Decrease in Incremental Recovery

When incremental EOR recovery decreases by 15 per cent the private NPVR decreases by 39 per cent and government NPVR decreases by some 24 per cent, at the 10 per cent discount rate. This means that the company shoulders much of the technological risk in the project, as it should. On the other hand the result illustrates perverse policy because governments take a bigger slice of a diminished net revenue, resulting in this case from less favourable technological factors. The fiscal regime is not efficient in the sense of being aligned to economic rent. However, this project is still economically viable at a 10 per cent real discount rate. Thus the economics of this particular project are so good that even when incremental production decreases by 15 per cent the project remains profitable.

3.3.2 Net Present Value Revenue Shares

An analysis of the changes in net revenue shares caused by changes in oil prices and recovery fractions is a worthwhile exercise in determining who shares the risks and benefits under different conditions, and whether the fiscal regimes are working effectively in capturing a part of the true economic rent. The net present value revenue shares are given in Table 3.3.

In all cases, the greatest share of these revenues is received by the province. The variance in the revenue shares is generally small under the different pricing and recovery scenarios and generally amounts to a trade-off between the province and the company, with the federal government's revenue share remaining relatively constant throughout.

In the previous section we have touched upon revenue shares and now they are examined in more detail.

Net Present Value Revenue Shares

Unrisked Base Case - Constant Real Prices

Even with the royalty relief provided by Section 4.2 the province is shown to have the highest net revenue share of 46 per cent, followed by the federal government and finally the company. As shown in Table 3.3 the PV revenues are positive even at a 15 per cent real discount rate for both governments and the private sector. Under the unrisked base case scenario all three participants realize an above normal profit, i.e. they share in economic rent defined as the return above 10 per cent real.

In the unrisked base case the NPVR, shares at a 10 per cent discount rate are made up as follows:

Net Present Value Revenue
at a 10 per cent discount rate

		Millions of 1983 dollars		Revenue Share %
Alberta:	Royalties	152.13		39.64
	Income Taxes	25.64		6.68
	Total		177.77	46.32
Federal:	PGRT	46.37		12.08
	Income Taxes	101.93		26.56
	Total		148.30	38.64
Private Sector:	Net Cash Flow		57.70	15.04
TOTAL NET REVENUE			383.77	100.00

Increasing Real Prices

With higher real prices the change in net revenue shares is small. The federal government and company shares increase marginally while the provincial government's share decreases slightly. In spite of the increase in royalty rates the provinces's share decreases and the company's share increases slightly. This is because an increase in royalty rates leads to an increase in royalty deductions in earlier years under Section 4.2 of the Petroleum Royalty Regulations. The increase in royalties payable in later years of the project life is not large enough to compensate for the increase in royalty deductions after discounting.

In spite of the large changes in oil prices, revenue shares vary very little. Thus, taxes and royalties are insentitive in capturing the greater potential economic rents available from an increase in real oil prices. The consequence of this rigidity is that the fiscal regime would not be efficient for significantly different price levels. It provides more or less fixed shares in net revenues which may be satisfactory in so far as sharing is concerned but it doesn't efficiently manage the resource. As a general principal the governments should collect a larger percentage of a larger economic rent and the converse, reducing the government share to zero at the point there is minimal rent available.

Decreasing Real Prices

As was the case for a real price increase, when real prices decrease the change in the revenue shares of the respective participants is small. The province's share is slightly higher while the federal government's share and the company's share are slightly lower. Once again taxes and royalties appear to be insensitive to a change in oil prices. Since the revenue shares of provincial and federal government's change very little when real prices decrease it appears that under the present fiscal regime the government and the private sector share equally in the risk associated with uncertainty of oil prices, provided that the project is profitable. With even lower prices the private sector

would incur losses while the governments were still taking revenues. At that point the companies would be gouged.

Oil Prices Deregulated

When oil prices are deregulated the province's share increases to about 56 per cent, the company's share decreases to only 5 per cent and the federal government's share remains unchanged. The project becomes only marginally profitable for the private sector. Deregulation of oil prices by the federal government will require adjustments in provincial royalties by Alberta.

Increase in Incremental Recovery

When incremental recovery increases both the provincial and federal government's revenue shares fall slightly while the company's share increases by about 1.5 percentage points. It may be noted that the net revenue shares of the respective participants are more sensitive to an increase in incremental recovery than they are to an increase in price, although in neither case do the shares change very much.

Decrease in Incremental Recovery

When incremental recovery decreases the province's share increases slightly and the company's share decreases by about 1 percentage point. Once again the effects of technological and

geological uncertainty on the company return are not cushioned by the fiscal regime.

3.3.3 Real Supply Costs

The estimated real resource supply cost without taxes and royalties may be defined to be a social supply cost whereas the supply cost with taxes and royalties may be termed a private supply cost. The social and private supply costs for each sensitivity case, at the 10 per cent real discount rate, are shown in Table 3.4. Since the producer always views taxes and royalties as an additional cost which must be covered before a project may be brought on stream, the private supply cost is normally higher than the social supply cost.

As discussed in Section 3.3.1 our cases without taxes and royalties do not fully represent the social perspective because they include the old oil/new oil pricing differentials of existing legislation. Only the case with oil prices deregulated, without taxes and royalties, represents the true social perspective. However the difference in social supply cost between all the various cases, as shown in Table 3.4, is only at maximum some $31.00 per cubic metre. Our best estimate of social supply cost is $126.95 while the unrisked base case analysis itself indicates $124.85 per cubic metre. To attempt to avoid unnecessary complexities we ignore these imperfections of analysis in the

subsequent discussion, and simply refer to the estimated supply cost without taxes and royalties as the social supply cost.

Social and Private Supply Costs

Unrisked Base Case - Constant Real Prices

This EOR project is profitable under all the conditions tested and therefore, as shown in Table 3.4, the social and private supply costs for this incremental EOR oil are lower than the wellhead price. The larger the difference between the social supply cost and the effective wellhead price, the higher the indicated above normal profits, i.e. economic rent, in the project. For the unrisked base case, the private supply cost of $160 per cubic metre is some $111 per cubic metre less than the wellhead price of some $271 per cubic metre.

The difference between the social supply cost and the wellhead price of some $146 per cubic metre ($271 - $125) is the amount of economic rent which is to be distributed between the federal and provincial governments and the company. Referring back to the sharing of NPVR, in Table 3.3 this potential economic rent is shared some 46 per cent by Alberta, about 39 per cent by the Federal Government and 15 per cent by the private sector. That is, Alberta gets $67 per cubic metre, the federal government gets $57 per cubic metre and the private sector gets $22 per cubic metre.

To summarize it is useful to tabulate the unrisked base case results, assuming a 10 per cent real discount rate;

		$/M3 Produced
Economic Rent:	Alberta	67
	Federal	57
	Private Sector	22
Real Resource Costs		125
Wellhead Price		27[1]

Increasing Real Prices

Both the social and private supply costs are higher with higher prices; for two reasons; 1) oil or related products are themselves inputs to the EOR process and, 2) the taxes and royalties in the private supply cost are a function of the wellhead price. The social supply cost rises from $125 to $137 per cubic metre and the private supply cost rises to $175 per cubic metre.

Decreasing Real Prices

With real oil prices decreasing by 5 per cent annually over the life of the project, both the social and private supply costs are lower than the respective supply costs for the unrisked base case. This is for the same reasons that were given for the rising real price case.

Oil Prices Deregulated

Even though incremental production plus a small portion of remaining base case production receives NORP under the existing fiscal regime if all oil prices are deregulated such that all oil receives NORP both the social and private supply costs, as we have defined these terms, increases slightly. This is for two reasons; 1) oil or related products are inputs into the EOR process and hence deregulation of oil prices leads to higher operating costs for EOR projects, and, 2) royalties and taxes would increase if oil prices were deregulated.

Increase in Incremental Recovery

As shown in Table 3.4, when incremental recovery increases the social supply cost decreases a few dollars. This results in an increase in the amount of economic rent to be shared between participants. At the same time the private supply cost increases as the private sector pays somewhat higher royalties and taxes. On balance however the private sector share of economic rent increases quite substantially, as discussed in Section 3.3.2.

Decreases in Incremental Recovery

When incremental recovery decreases the social supply cost increases by some $18 per cubic metre. This is because real costs remain constant while discounted production decreases. Generally

one would expect the private supply cost to decrease when production decreases. However, this is not the case for this project, as shown in Table 3.4 indicating that the decrease in discounted production more than offsets the decrease in taxes and royalties.

3.3.4 Results

The results of the sensitivity analyses indicate that:

1. Under the unrisked base case scenario (constant real prices) and the existing fiscal regime for EOR projects the project generates a real rate of return which is greater than 40 per cent.

2. Both decreasing real prices and deregulation of oil prices have a negative impact on the economics of the project. The negative impact of deregulation of oil prices is problematical from a policy viewpoint, and the impact is greater than the negative impact of decreasing real prices.

3. Increasing real prices improve the economics of the project.

4. An increase in incremental recovery improves the economics of the project.

5 A decrease in incremental recovery results in less favourable economics. However, this project remains economically viable even when incremental recovery decreases by 15 per cent.

6. Under all pricing and incremental recovery cases the project is estimated to be economically viable at a 15 per cent real discount rate.

Conclusions

Overall the fiscal regime appears unresponsive to change in price and the resultant change in private sector profitability, and appears somewhat perverse in the case of the Swan Hills project, in that it takes a slightly larger share of available economic rents as private sector profitibality is reduced. Generally the sharing of potential economic rent appears to be overly rigid. The governments do not take a larger percentage of a larger economic rent and the converse. With decreasing world oil prices it would appear that the private sector could incur losses while the governments were still collecting substantial revenues.

The fiscal system is far from perfect and will almost certainly need to be changed again in the near future. Deregulation of oil prices has a significant negative impact on the economics of the EOR project. This is one problem which will have to be solved as domestic oil prices move to market levels. The fiscal regime

cannot therefore be viewed as robust for many years and consequently the private sector is faced with a high degree of political risk in addition to the risks of an economic and technological nature. Deregulation of oil prices by the federal government would require adjustment to provincial royalties by Alberta.

The return to the private sector increases substantially as technical recovery is improved. This provides an incentive for maximizing oil recovery and for efficiency but it also is an incentive to the private sector to inflate estimates of EOR recovery in the context of present old oil/new oil price differentials and the "fixed ratio method" of deeming what production is considered as EOR, in the existing fiscal regimes. This type of problem is pervasive under the old oil/new oil arrangement. However, it should be noted that the AERCB Public Hearing Process acts as a mechanism to prevent this. The other side of the coin is that risks of reduced recovery are shouldered largely by the private sector, if the reduction is detected early in the field's production life, because the governments take a larger slice of net present value revenues as profits decrease under reduced recovery factors.

Under most conditions, and typified by the unrisked base case conditions of flat real oil prices, this project provides potential economic rents which are shared 46 per cent by Alberta, 39 per cent by the federal government and some 15 per cent by the private sector.

The estimated real resource cost of this EOR oil, i.e. the social supply cost, is around $125 per cubic metre provided that the recovery rates are realized. The private supply cost is in the range of about $156 to $256 per cubic metre depending on assumptions, and in the unrisked base case we have assumed a wellhead price of some $271 per cubic metre. The project is theretore estimated to be economically viable under a wide range of assumptions. In the unrisked base case the project costs and economic rents are estimated to be shared as follows.

Net Present Value Revenue

	millions of $ 1983	%
Province	177.80	46.3
Federal	148.33	38.6
Private Sector	57.74	15.1
Total Economic Rent	383.83	100.0
Real Resource Costs	303.47	
Gross Revenue	687.30	

4. CASE 2 - NIPISI GILWOOD UNIT 1

4.1 Introduction

This section examines the hydrocarbon miscible flood in Nipisi Gilwood Unit 1 under various conditions of price, incremental recovery fractions and cost of money. The major objective of this analysis is to look at the effect of various price assumptions and incremental recovery fractions on the economics of this project. This will be done by analyzing the net present value revenues and real supply cost both with and without taxes and royalties for various costs of money. This analysis will also look at the respective revenue shares of the federal and provincial governments and the company.

The paper proceeds with a brief description of Nipisi Gilwood Unit 1. We then discuss the effect of variations in oil prices and incremental recovery fractions on the economics of Nipisi Gilwood Unit 1.

4.2 Nipisi Gilwood Unit 1[7]

4.2.1 Geology and Location

Nipisi Gilwood Unit 1 is located approximately 300 kilometres northwest of Edmonton, Alberta.

Nipisi Gilwood is a member of the Watt Mountain Formation which is of Middle Devonian age. Production is from deltaic Gilwood sandstones. There are 3 main producing horizons:

1) alluvial plain - braided stream channel sands
2) delta plain - stacked distributory channel sands
3) delta front - sheet sands.

The producing sands vary in coarseness from silt to pebble and the gross pay thickness is 6-20 metres.

4.2.2 Background

The Nipisi Gilwood A Pool was discovered in 1965. Original oil-in-place (OOIP) was estimated to be 114.0 million cubic metres. In 1969 a waterflood project was developed over a 24 780 hectare area. The presently estimated original oil-in-place and recoverable reserves for the waterflood are 110 million cubic metres and 47.3 million cubic metres respectively. There are 236 wells in the waterflood area of which 37 are injectors and 106 are active producers.

Development of the miscible flood project began in 1983 and injection began February 1, 1984.

4.2.3 Nipisi Gilwood Unit 1 - Miscible Flood Project

In 1983 the expenditures for Nipisi Gilwood Unit 1, a six section miscible flood EOR project, in part of the waterflood area of the Nipisi Gilwood A Pool were incurred. However, the actual miscible flood started February 1, 1984. Original oil-in-place (OOIP), subject to miscible flooding, is estimated to be 12.4 million cubic metres yielding recoverable reserves of 2.73 million cubic metres. Production forecasts for the base case (waterflood) and the total project (waterflood + miscible flood) are presented in Appendix B.

The miscible flood consists of six inverted 9-spot patterns with 160 acre well spacing. In order to accommodate 160 acre well spacing eight additional production wells and four additional injection wells were added. One of the four additional injection wells was drilled outside the six section area in order to contain the flood to the six section area and provide pressure support. This well will be used for water injection only.

Seven of the additional production wells are conventional wells while one well is a whipstocked well under the lake used to induce flow in a south-north direction under the lake. This additional drilling is also expected to improve the waterflood recovery by an additional 4.5 per cent of OOIP.

Unit gas and NGL production from the area will act as the solvent supply eliminating the need to purchase outside injection fluids. Injection fluids will come by pipeline from the Nipisi Gas Plant at Mitsue.

Original plans are to inject a 13 per cent hydrocarbon pore volume (HCPV) solvent slug in alternating cycles with water. This will be followed by a 31 per cent HCPV chase gas slug injected in alternating cycles with water. Solvent will be injected for 4.75 years starting in February, 1984 and chase gas will be injected for 9.1 years beginning in 1988. Total project life is estimated to be 20 years.

4.3 Cash Flow Results and Sensitivities

4.3.1 Net Present Value Revenues

Net Present Value Revenue results at various discount rates are given in Table 4.1.

Unrisked Base Case - Constant Real Prices

Net present value revenues are positive at all real discount rates in the range up to 15 per cent both with and without taxes and royalties. Under the current fiscal regime which applies to enhanced oil recovery projects in the province of Alberta, and

constant real oil prices, the Nipisi Gilwood Unit 1 hydrocarbon miscible flood is economically feasible.

Increasing Real Prices

Under the increasing real price case both the NORP and Old Oil price were increased annually by 5 per cent in real terms.

In this case net present value revenues without taxes and royalties are higher than they are for the unrisked base case by some 64 per cent, and by some 53 per cent with taxes and royalties, at a 10 per cent discount rate.

Under the existing fiscal regime federal and provicial tax rates and the PGRT rate do not change as prices rise. However, the existing royalty rate formula for both NORP and conventional old oil (COOP) is a function of the price of oil. As a result royalties increase enabling the province to capture a marginally higher portion of total revenue. The private sector however, is left with almost the same share of a higher NPVR, showing that its upside potential is kept intact.

Decreasing Real Prices

Under the decreasing real price case real oil prices are decreased by 5 per cent annually. Net present value revenues without taxes and royalties decrease by $94 million or 42 per cent

at a 10 per cent discount rate. Thus when real oil prices decrease the amount of economic rent to be distributed among the resource owners decreases.

In the decreasing real price case net present value revenues with taxes and royalties decrease by some 34.9 per cent at a 10 per cent discount rate. Tax rates are insensitive to a change in oil prices but royalties decrease slightly. However, the decrease in royalties is not nearly large enough to absorb the impact of such a large price decrease.

The private sector share in NPVR increases slightly, from some 17 per cent to about 19 per cent, which is in the correct direction under adverse price conditions. It may be noted that this result is contrary to the Swan Hills analysis wherein lower prices tended to reduce the private sector share.

Oil Prices Deregulated

When oil prices are deregulated all oil receives NORP regardless of whether it is currently classified as old or new oil.

Private sector NPVR is reduced from some $38 million in the unrisked base case to $35 million, at a 10 per cent discount rate. As shown in Table 4.1, deregulation of oil prices initially eliminates any incentives, provided by current pricing policy, for

this EOR project and has a slight negative impact on the economics of the project.

In Table 4.1, private sector NPVR is lower when oil prices are deregulated than they are under the unrisked base case because of two main reasons:

1) The incrementally higher price received for production which is in reality non-incremental in the EOR scheme is lost when prices are deregulated.

2) When all production receives NORP all production pays NORP royalties. Although the marginal royalty rates for NORP oil are less than for old oil total royalties payable increase because of the higher price. This is shown in Table 4.2.

It may also be seen from Table 4.1 that deregulation of oil prices has a slight negative impact on the economics of the project. In the unrisked base case the project is profitable at all real discount rates. When oil prices are deregulated the project becomes less economic from the company's viewpoint at a 10 per cent real cost of money. The decrease in NPVR is primarily due to an increase in royalties payable, as shown in Table 4.2.

Deregulation of oil prices might be a welcome policy change from the viewpoint of the petroleum industry as a whole. However, on the basis of these results it would appear that if the government were to adopt a policy whereby oil prices would be deregulated it would result in fewer new EOR projects coming on stream in the absence of modified incentives and could possibly lead to the shutdown of existing EOR schemes. In order to encourage continued and future development of high cost, high risk EOR projects the government will have to provide different EOR incentives.

Increase in Incremental Recovery

In this case incremental recovery (i.e. total remaining recoverable reserves less remaining waterflood reserves) is increased by 15 per cent. This sensitivity case, along with the case where incremental reserves are decreased by 15 per cent, illustrate the effect of technological and geological uncertainty on the economics of the EOR project. These cases also show the response of royalties and taxes to variations in incremental recovery fractions.

Comparison of the NPVR under the unrisked base case with that for the increase in incremental recovery case shows that social net present value revenues increase by 22 per cent and private sector NPVR increases by 18 per cent, at a 10 per cent discount rate, when incremental recovery increases by 15 per cent.

Decrease in Incremental Recovery

Under this production scenario prices remain constant in real terms but incremental production is decreased by 15 per cent. Private sector NPVR decreases by about 18 per cent and social NPVR by about 22 per cent. The project, however, remains economically viable.

Overall the existing tax and royalty structure for EOR projects is relatively insensitive to changes in incremental production and the company is left to bear the burden of technological and geological uncertainty.

4.3.2 Net Present Value Revenue Shares

Analysis of the net revenue shares of the resource owners under various pricing and production assumptions is a useful instrument in determining how risk and benefits are shared between the participants in EOR projects. Present value net revenue shares for the Federal and Provincial governments and the company are given in Table 4.3.

In all cases, the province receives the greatest share of available economic rents followed by the federal government and finally the company. Revenue shares are relatively insensitive to changes in pricing and production assumptions.

Net Present Value Revenue Shares

Unrisked Base Case - Constant Real Prices

In the unrisked base case the province receives 45 per cent of net revenues at a 10 per cent discount rate followed by the federal government with 38 per cent and the province with 17 per cent. Net revenue shares are positive at all real discount rates indicating that all three participants realize a profit.

In the unrisked base case net present value revenue shares at a 10 per cent real discount rate consist of the following components:

Net Present Value Revenue
at a 10 per cent discount rate

		Millions of 1983 dollars		Revenue Share %
Alberta:	Royalties	85.40		38.08
	Income taxes	15.29		6.82
	Total		100.69	44.90
Federal Government:	PGRT	26.91		12.00
	Income taxes	58.95		26.29
	Total		85.86	38.29
Private Sector:	Net Cash Flow		37.68	16.80
TOTAL NET REVENUE			224.24	100.00

As discussed earlier, Section 4.2 of the Alberta Petroleum Royalty Regulations provides a royalty deduction during the injection period which reduces the effect of high costs on the economics of EOR projects. In spite of this incentive the province still receives over 44 per cent of total net revenue at a 10 per cent real discount rate. The province is unquestionably in the best position to provide further incentives for the development of EOR projects.

Increasing Real Prices

In the rising real price case the province's net revenue share increases by one per cent due to an increase in royalties, and the federal government's share increases fractionally from higher income takes. These changes result in a reduction in the company's net revenue share of some 1.10 per cent, at a 10 per cent discount rate. This is shown in Table 4.3.

Decreasing Real Prices

Royalties, as a function of price, decrease along with prices resulting in a 2 per cent reduction in the province's net revenue share, at a 10 per cent discount rate. The federal government's share remains constant and the company's position improves by approximately 2 per cent. Once again taxes and royalties are relatively insensitive to a price change however, it should be noted that net revenue shares are more responsive to a price

decrease than they are to a price increase. This is because of the calibration of the royalty function.

Oil Prices Deregulated

Deregulation of oil prices has a slight negative effect on the economics of the project from the viewpoint of the company. The federal government's share changes very little but a transfer of revenue share from the company to the province takes place. The province's net present value revenue share increases by some 3 per cent and the company's share decreases by over 3 per cent. The major reason for this, as discussed in Section 4.3.1, is the increase in royalties which occur when all oil production receives NORP.

Increase in Incremental Recovery

A 15 per cent increase in incremental production results in a 0.4 per cent increase in the province's net revenue share, a .13 per cent increase in the federal government's net revenue share and a 0.52 per cent decrease in the company's share. For this project and the others which have been examined net revenue shares of the respective participants do not change very much, but in this case they are more sensitive to an increase in price than they are to an increase in incremental production whereas in South Swan Hills the opposite holds true.

Decrease in Incremental Recovery

When incremental recovery decreases both the provincial and federal government's net revenue shares decrease and the company's increases. The decrease in the province's net revenue share is only 0.67 per cent and is primarily due to a decrease in royalties. The change in the federal government's share is in response to a reduction in taxable income. Despite the fact that the economics of the project worsens the company's net revenue share is approximately 0.87 per cent higher than it is for the unrisked base case. Nonetheless judging by the size of the change in revenue shares the current tax and royalty system is relatively insensitive to a change in incremental recovery, and the company assumes most of the risk associated with technological and geological uncertainty.

4.3.3 Real Supply Costs

The estimated real resource supply cost without taxes and royalties may be defined to be a social supply cost whereas the real supply cost with taxes and royalties may be termed the private supply cost. Both the social and private supply costs for each sensitivity case at a 10 per cent real discount rate are presented in Table 4.4. Supply costs for the total project and base case project are presented in Appendix C.

Recall that our cases without taxes and royalties do not fully represent the social perspective because they include the old oil/new oil pricing differentials of existing legislation. Only the case with oil prices deregulated, without taxes and royalties, represents the true social perspective. In an effort to avoid unnecessary complications we ignore this problem in our discussion and refer to the supply cost without taxes and royalties as the social supply cost and the supply cost with taxes and royalties included as the private supply cost.

Social and Private Supply Costs

Unrisked Base Case - Constant Real Prices

As shown in Table 4.4, the social supply cost for Nipisi Gilwood Unit 1 is $99.26 per cubic metre ($15.77 per barrel) which is considerably less than the effective wellhead price of $229.69 per cubic metre ($36.50 per barrel). The difference between the effective wellhead selling price and the social supply cost is a measure of the economic rent. With oil prices assumed to be constant in real terms, crude oil from this project generates $130.43 per cubic metre ($20.73 per barrel) in economic rent of which the province receives 45 per cent, the federal government gets 38 per cent and the company gets the remaining 17 per cent.

This is summarized below:

Economic Rent:	Alberta	59.00
	Federal government	50.00
	Private sector	22.00
Real resource costs		99.00
Wellhead price		230.00

The private supply cost for Nipisi Gilwood Unit 1 is $206.71 per cubic metre ($32.85 per barrel), which consists of cost of taxes and royalties of $107.45 per cubic metre ($17.07 per barrel) plus $99.26 for real resources.

Increasing Real Prices

Both the social and private supply costs are higher when real prices are assumed to increase. The social supply cost is higher because a portion of operating costs are a function of the price of oil. The private supply cost increases because of two reasons: 1) oil or related products are themselves inputs to the EOR process; 2) royalties are a function of the wellhead price. The social supply cost increases by about 2 per cent whereas the private supply cost increases by about 43 per cent at a 10 per cent real discount rate.

Decreasing Real Prices

Social and private supply costs are lower in the decreasing real price case than they are in the unrisked base case. This is for

the same reasons that were given above for the increasing real price case. In Table 4.4 the private supply cost is shown to be considerably less than the effective wellhead price.

Oil Prices Deregulated

The social supply cost when oil prices are deregulated is slightly higher than it is for the unrisked base case. However, the private supply cost increases considerably from $207 per cubic metre to $237 per cubic metre, a 14.5 per cent increase. This is because royalties and taxes increase when oil prices are deregulated. Furthermore, the effective wellhead price increases by 11.5 per cent to about $256 per cubic metre and the project remains economically viable.

Increase in Incremental Recovery

When incremental recovery increases the social supply cost decreases by $12.57 per cubic metre, or 12.7 per cent because the average fixed operating costs per unit of production decreases by more than the increase in variable operating costs. However, there is virtually no change in the private supply cost indicating that the tax and royalty system fails to capture a larger share of available economic rent.

Decrease in Incremental Recovery

In response to a decrease in incremental recovery the social supply cost increases and the private supply cost changes very little. This is for the same reasons given above for an increase in incremental recovery.

4.3.4 Results

1. Under unrisked base case conditions, with flat real oil prices the Nipisi Gilwood Unit 1 hydrocarbon miscible flood is estimated to be profitable.

2. The project remains economic in all sensitivity cases except when real oil prices are deregulated and the real cost of money is 15 per cent.

3. Increasing real prices improve the economics of the project but lowers the company's net present value revenue share.

4. Decreasing real prices and deregulation of oil prices both have a significant negative impact on the economics of the project. When real prices decrease the company's net revenue share increases, but when oil prices are deregulated the company's net revenue share decreases.

5. An increase in incremental recovery improves the economics of the project but lowers the company's net revenue share. A decrease in incremental recovery reduces net present value revenues for the project but increases the company's net revenue share.

Conclusions

Overall the fiscal regime is relatively insensitive to changes in price and the resultant change in private sector profitability. Despite this rigidity it is consistent with efficient resource management taking a slightly larger share of higher above normal profits and a smaller share of lower potential economic rent.

Deregulation of oil prices has a negative impact on the economics of the project. Although the magnitude of the impact of deregulation is relatively small it still remains a problem which must be solved as domestic oil prices move to market levels.

In response to changes in recovery fractions the provincial share increases slightly as recovery increases and decreases as recovery decreases. Unfortunately these changes in revenue shares are small relative to the change in recovery fractions and the private sector continues to bear the burden of technological and geological risk associated with the project.

In general the existing fiscal regime is overly rigid and will almost certainly need to be changed in the near future to ensure efficient management of the resource and encourage the development of new EOR projects and possibly the continuation of existing projects.

The rigidity of the fiscal system is exemplified by the small variations in revenue shares which result under various price and recovery scenarios. Because of the fixed nature of the PGRT and federal income taxes the federal share has little variance ranging from a low of 37.8 per cent when real prices are decreasing to a high of 38.6 per cent when oil prices are increasing. The province's share ranges from a low of 43.3 per cent when real prices are decreasing to a high of 48 per cent when oil prices are deregulated. After the governments take their share of potential economic rents the private sector is left with a low of 13.6 per cent in the deregulated oil price case and a high of 18.9 per cent in the decreasing real price case.

In spite of the high overall government take in each case the project remains profitable in all cases from both the social and private perspective at a 10 per cent discount rate.

5. CASE 3 - VIOLET GROVE AB LEASE

5.1 Introduction

This section examines the response of project economics and evaluates how the risks are shared and net present value revenue divided between participants under various pricing and production scenarios for the Violet Grove AB Lease hydrocarbon miscible flood. This is done by estimating net present value revenues and supply costs both with and without taxes and royalties for different sensitivity cases.

This section proceeds with a brief description of the Violet Grove AB Lease. We then discuss the effect of alternative pricing and incremental production scenarios on the project economics.

5.2 The Pembina Cardium Reservoir[8]

5.2.1 Background

A hydrocarbon miscible flood has been proposed for the Violet Grove AB Lease in the Pembina Cardium sandstone reservoir which is located approximately 100-125 kilometres south-west of Edmonton, Alberta.

The Pembina Cardium oil field was discovered in 1953 and has an area of some 191,669 hectares, being the largest conventional light density oil reservoir in Canada. Original oil-in-place is estimated to be 1.18 billion cubic metres (7.43 billion barrels). Initial established recoverable reserves are 131 thousand cubic metres (824.4 thousand barrels) of primary production and 108 thousand cubic metres (679.6 thousand barrels) of enhanced oil (water flood) recovery production. Cumulative production as of December 31, 1981 was 148.8 thousand cubic metres (936.7 thousand barrels) leaving 90.1 thousand cubic metres (567 thousand barrels) of remaining established reserves.[1]

5.2.2. Violet Grove AB Lease

Violet Grove AB Lease provides the potential for a small hydrocarbon miscible flood located in the Pembina Cardium Reservoir. Total project area is only 640 acres. The project is proposed to be set up using 5-spot patterns, 80 acre pattern size and 40 acre well spacing. There will be 8 producers and 8 injectors and the estimated economic life of the project is 40 years.

The proposed hydrocarbon flood will consist of a 10 per cent hydrocarbon pore volume (HCPV) solvent slug injected in alternating cycles with water to be followed by a 16 per cent HCPV chase gas slug.

Original oil-in-place (OOIP) is estimated to be 1.81 million cubic metres (11.4 million barrels). Total estimated recovery (including the miscible flood) is estimated to be 60 per cent of OOIP or 1.086 million cubic metres (6.83 million barrels).

Tertiary recovery is expected to account for .27 million cubic metres (1.71 million barrels).

5.3 Cash Flow Results and Sensitivities

5.3.1 Net Present Value Revenues

In this section Net Present Value Revenues (NPVR), shown in Table 5.1, are analyzed at various discount rates, under different pricing and production assumptions. The effect of the existing fiscal regime on project profitability is evaluated by comparing net present value revenues, at various discount rates, under different pricing and production assumptions with full taxes and royalties versus no taxes and royalties.

It should be noted that because of the old oil/new oil pricing components of existing legislation the cases without taxes and royalties do not represent the social perspective except when oil prices are deregulated (i.e. old oil/new oil pricing components are eliminated). Since the differential pricing effect upon this project is small, all cases without taxes and royalties may be viewed as reasonable approximations of the social return.

Unrisked Base Case - Constant Real Prices

Net present value revenues without taxes and royalties included are positive at all real discount rates. However, when taxes and royalties are included the project becomes marginally economic at a 10 per cent discount rate and uneconomic at a 15 per cent discount rate. In view of the high degree of economic, technological and geological uncertainty associated with enhanced oil recovery projects it is doubtful that a project that just recovers a 10 per cent real rate of return would proceed.

Increasing Real Prices

When real oil prices increase at 5 per cent annually net present value revenues without taxes and royalties at a 10 per cent discount rate are some $13 million or 154 per cent higher than in the unrisked base case and net present value revenues with taxes and royalties are some $3.2 million higher than they are in the unrisked base case. Furthermore, the project becomes profitable at a 15 per cent discount rate.

As is shown in Table 5.2 when real oil prices increase taxes and royalties increase. At a 10 per cent discount rate, economic rent is some $13 million higher in the increasing price case than in the unrisked base case. As is shown in Table 5.2, the governments take $10.2 million or 78 per cent of this rent leaving the private

sector with $2.8 million or 22 per cent of the additional economic rent.

Decreasing Real Prices

In Table 5.1 a 5 per cent annual decrease in oil prices is shown to have a negative impact on the economics of the project at all discount rates with and without taxes and royalties. Without taxes and royalties the project is marginally economic at the 10 per cent discount rate but becomes uneconomic at a 15 per cent discount rate. When taxes and royalties are included net present value revenue is negative at a 7 per cent discount rate.

In Table 5.2 both provincial and federal income tax are approximately zero, the PGRT is only some $.28 million or 24 per cent of net present value revenue. However, royalties account for approximately 182 per cent of available economic rent. Despite the negative impact of a decreasing real price scenario on the profitability of the project, the existing royalty formula is such that the province collects royalties even if the private sector is placed in a loss position. Obviously, under these circumstances the provincial government would have to provide royalty relief for the project to continue.

Oil Prices Deregulated

When oil prices are deregulated all oil produced receives NORP regardless of whether it is currently classified as old or new oil. Hence, the old oil/new oil pricing components of existing legislation are eliminated.

In Table 5.1, net present value revenue without taxes and royalties is approximately 7.5 per cent lower at a 10 per cent discount rate under the deregulated oil price case than it is for the unrisked base case. This decrease is largely a consequence of the effect of deregulation of oil prices on the portion of old oil production which qualifies for NORP in the base case (i.e., remaining water flood) under the fixed ratio method. Also in Table 5.1 net present value revenues with taxes and royalties are marginally negative at 10 per cent discount rate when prices are deregulated whereas in the unrisked base case the project is marginally economic. From the private sector's viewpoint deregulation of oil prices tips the balance of the economics of this particular project, from a marginally profitable situation to a marginal loss.

The various components included in a net present value calculation at a 10 per cent real discount rate are summarized in Table 5.2. In spite of the decrease in available economic rents which occurs when oil prices are deregulated, royalties are shown to increase whereas tax takes, including the PGRT, decrease.

Increase in Incremental Recovery

In Table 5.1 net present value revenues are some $3.4 million or 40 per cent higher without taxes and royalties when incremental recovery increases than net present value revenues for the unrisked base case at a 10 per cent discount rate. When taxes and royalties are included net present value revenues increase by $.73 million at a 10 per cent discount rate. In spite of the increase in incremental recovery the project remains uneconomic at a 15 per cent discount rate. Because of the small annual incremental production levels and long project life a 15 per cent increase in incremental production would have little influence on the investment decision of the private sector.

The effect of a 15 per cent increase in incremental recovery on taxes and royalties is shown in Table 5.2.

Decrease in Incremental Recovery

As shown in Table 5.1 a 15 per cent decrease in incremental recovery results in a decrease of some $3.5 million in net present value revenue without taxes and royalties and $.75 million with taxes and royalties included at a 10 per cent discount rate. In fact when taxes and royalties are included the project becomes uneconomic at a 10 per cent discount rate.

The various components of the net present value revenue calculation are given for a 10 per cent discount rate in Table 5.2. Note that once again royalties have the most predominant impact on the economics of the project accounting for 66 per cent of available economic rent.

5.3.2 Net Present Value Revenue Shares

In this section net revenue shares are analyzed under various pricing and production assumptions in order to show how the risks and benefits are shared between participants. Furthermore, the responsiveness of the existing fiscal regime for EOR projects in Alberta to changes in oil prices and incremental production is analyzed to determine its effectiveness in capturing a part of true economic rent. The net present value revenue shares are given in Table 5.3.

In all cases, the province receives the greatest share of available economic rent. Even when the project economics are unfavourable the province would still take a relatively high portion of net revenues. In the decreasing real price case the province actually receives 175 per cent of net present value revenue at a 10 per cent discount rate at the expense of the private sector.

Federal income taxes and the sheltered PGRT are more in step with the true economic rent and sharing the risk associated with price and production decreases, than the royalty.

Because the project is only marginally economic in the unrisked base case the company is vulnerable to any change in net revenue shares which occur as a result of changes in price and production. For the most part the company shares the major portion of the risks. In fact when real prices are decreasing, the company would operate at a loss while the province received royalties, in order for the project to proceed.

Net Present Value Revenue Shares

Unrisked Base Case - Constant Real Prices

As shown in Table 5.3 the province has the highest net revenue share of 58 per cent at a 10 per cent discount rate followed by the federal government and finally the company. Note that the project is only marginally economic at a 10 per cent discount rate and becomes uneconomic for a real rate of return between 10 and 15 per cent.

The NPVR shares for the unrisked base case at a 10 per cent discount rate are summarized below.

Net Present Value Revenue
at a 10 per cent discount rate

		Millions of 1983 dollars		Revenue Share %
Alberta:	Royalties	4.37		52.15
	Income taxes	.47		5.61
	Total		4.34	57.76
Federal Government:	PGRT	1.14		13.60
	Income taxes	1.98		23.63
	Total		3.12	37.23
Private Sector:	Net Cash Flow		.42	5.01
TOTAL NET REVENUE			6.38	100.00

Because of the marginal nature of this project the existing fiscal regime is quite influential in determining whether the project proceeds or not. As shown above the governments take 95 per cent of NPVR, and royalties alone capture some 52 per cent of available economic rent at a 10 per cent discount rate. Under the existing royalty formula the province receives royalties even if there is no pure economic rent available, even after Section 4.2 EOR royalty relief. Since a large number of technically feasible EOR projects are only marginally economic at best, the PGRT should be put aside by the federal government and the province should amend the royalty formula pertaining to EOR in order to promote the development of high risk EOR projects.

Increasing Real Prices

When oil prices are increasing the province's net revenue share is approximately 13 per cent lower than it is in the unrisked base case, while the federal government's share increases by 1 per cent and the company's net revenue share rises. Furthermore, the project becomes profitable at a 15 per cent discount rate. The large changes in net revenue shares which occurs when oil prices increase demonstrates the risk sharing aspects of the existing fiscal regime.

Both income taxes and the PGRT are closely correlated with available net revenues, provided the project is profitable. When economic rent is low taxes are low and when rents are high taxes are high. However, the effective tax rate is unresponsive to changes in price or production. Hence tax rates are such that the Federal government shares in both risk and benefits of the project by retaining a more or less constant share of net revenues.

On the other hand the province shares little of the risk as is illustrated in Table 5.3. In the unrisked base case when the project is marginally economic the province takes a high share of available economic rent in the form of royalties. When real prices are increasing the province receives a smaller portion of available economic rent than it did in the unrisked base case. Consequently, the province shares little of the risk associated

with the EOR projects (other than Section 4.2 royalty relief and provincial income tax) but allows the private sector to share in the benefits which result from higher prices.

Decreasing Real Prices

When oil prices decrease by 5 per cent annually the project is not economically feasible at discount rates above 5 per cent. In Table 5.3 the province's share is shown to be greater than available NPVR for discount rates over 10 per cent. Royalties are the predominant reason for this as shown in Table 5.2. Unquestionably the existing royalty formula would have to be adjusted in circumstances of lower prices. Furthermore, the province does not participate in risk sharing. On the other hand if net present value revenues approach zero the federal government's net revenue share approaches zero. As shown in Table 5.3 at a 15 per cent discount rate the federal government actually shares the loss with the company.

Oil Prices Deregulated

When oil prices are deregulated the province's share increases to about 64 per cent, the federal government's share drops slightly and the company's share plummets to -1.29 per cent at a 10 per cent discount rate. Once again the province benefits at the expense of putting the private sector into a loss position. The elimination of the old oil/new oil price components of

existing legislation will require an adjustment in the Alberta royalty regime.

Increase in Incremental Recovery

An increase in incremental recovery results in a 5 per cent decrease in the province's share, a 5 per cent increase in the company's share and a slight increase in the federal government's share at a 10 per cent discount rate as shown in Table 5.3. Despite the increase in the company's net revenue share the project still remains marginally economic at a 10 per cent discount rate and uneconomic at a 15 per cent discount rate.

Decrease in Incremental Recovery

A decrease in incremental recovery has the same effect on net revenue shares as the decreasing oil price case has with a large increase in the province's net revenue share, small decrease in the federal government's share and a large decrease in the company's net present value revenue share.

5.3.3 Real Supply Costs

The private and social supply costs may be defined as the real resource supply cost with and without taxes and royalties respectively. The social and private supply costs along with

their effective wellhead prices are shown in Table 5.4 for a 10 per cent discount rate.

Recall from the discussion in Section 5.3.1 that only the case with oil prices deregulated, without taxes and royalties, represents the true social perspective. Estimates in Table 5.4, of social supply cost are shown to range between $140.85 per cubic metre ($22.37 per barrel) and $189.12 per cubic metre ($30.05 per barrel), with the oil prices deregulated case estimate being $161.72 per cubic metre ($25.70 per barrel).

Social and Private Supply Costs

Unrisked Base Case - Constant Real Prices

As shown in Table 5.4 the social and private supply costs are $161.30 per cubic metre ($25.63 per barrel) and $261.24 per cubic metre ($41.51 per barrel) respectively. Since both the social and private supply costs are less than the effective wellhead price the project is just profitable at a 10 per cent discount rate in the private perspective.

Economic rent may be defined as the difference between the social supply cost and effective wellhead price, and is some $105.84 per cubic metre ($16.82 per barrel) at a 10 per cent discount rate. This rent is divided between the provincial and federal governments and the company as follows:

Distribution of Economic Rent
$/m^3 Produced

Alberta	61.00
Federal government	40.00
Private sector	5.00
Real resource costs	161.00
Wellhead price	267.00

Increasing Real Prices

Both the social and private supply costs are higher in the increasing price case than they are in the unrisked base case. This can be expected because: 1) oil or related products are themselves inputs to the EOR process and tend to increase costs; 2) the taxes and royalties in the private supply cost are a function of the wellhead price and significantly increase private costs. This is illustrated in Table 5.4 where the social supply cost rises by $2.40 per cubic metre ($.38 per barrel) while the private supply cost rises by some $127.20 per cubic metre ($20.21 per barrel) to $388.94 per cubic metre ($61.81 per barrel).

Decreasing Real Prices

For the same reasons given for the rising real price scenario a 5 per cent annual decrease in oil prices results in a decrease in both the social and private supply costs. The social supply cost

falls by $2.84 per cubic metre to $158.46 per cubic metre ($25.18 per barrel) and the private supply cost falls from $261.24 per cubic metre (41.51 per barrel) to $188.19 per cubic metre ($29.90 per barrel). Since the private supply cost is greater than the effective wellhead price the project is unprofitable from the viewpoint of the private sector.

Oil Prices Deregulated

Deregulation of oil prices has little effect on either the social or private supply costs for this project as shown in Table 5.4. The social supply costs increase by $.42 per cubic metre ($.07 per barrel) while the private supply cost decreases by $1.23 per cubic metre ($.20 per barrel).

Increase in Incremental Recovery

When incremental recovery increases both production and taxes and royalties increase. The net effect is that the social supply cost decreases from $161.30 per cubic metre ($25.63 per barrel) to $140.85 per cubic metre ($22.37 per barrel). Because royalties are a function of production this puts upwards pressure on the private supply cost and they might increase. However, this is not the case for this project, as shown in Table 5.4, the reason being that since this project is marginal at best at a 10 per cent discount rate, the increase in discounted production more than offsets the increase in taxes and royalties.

Decrease in Incremental Recovery

As would be expected supply costs respond to a 15 per cent decrease in incremental recovery in the opposite direction that they responded to an increase in incremental recovery for the same reasons. In Table 5.4 the social supply cost increases by $27.82 per cubic metre ($4.42 per barrel) while the private supply cost increases by $3.91 per cubic metre ($.62 per barrel) to $265.15 per metre ($42.13 per barrel).

5.3.4 Results

The results of the sensitivity analysis indicate that:

1. Under the unrisked base case scenario (constant real prices) and the existing fiscal regime for EOR projects, Violet Grove AB Lease is at best marginally economic to the private sector, at a 10 per cent discount rate and becomes uneconomic when the real cost of money increases to 15 per cent.

2. The company's profit margin increases when real oil prices increase and when incremental recovery increases.

3. The project is uneconomic at a 10 per cent discount rate when real prices are decreasing, oil prices are deregulated and incremental recovery decreases.

4. At a 10 per cent discount rate the true social supply cost is some $162.00 per cubic metre as compared to a deregulated wellhead price of $259.00 per cubic metre. The project is therefore highly beneficial from a social viewpoint.

5. The project is uneconomic to the company at a 15 per cent real discount rate in all cases except when real prices are increasing.

Conclusions

The existing fiscal regime for EOR projects in the province of Alberta can actually increase the economic risk for marginal projects like Violet Grove AB Lease. As private sector profitability decreases the share of economic rents going to the governments increases. This is primarily due to the royalty formula for old and new oil. Despite the royalty relief provided by Section 4.2 royalties payable are always positive and often times greater than available economic rent. When real prices are decreasing, oil prices are deregulated, or incremental recovery decreases the private sector incurs a loss while the governments collect revenues.

Because a large number of potential EOR projects are risky existing legislation will need to be changed to reduce the risk facing the private sector and promote the development of EOR projects.

Unlike the highly profitable projects such as South Swan Hills and Nipisi Gilwood Unit 1 potential economic rents are very sensitive to changes in prices and incremental recovery in Violet Grove AB Lease. The province's share ranges from a low of 44.91 per cent in the increasing real price case to a high of 175 per cent of available net revenues in the decreasing real price case. The federal government's net revenue share was relatively insensitive to changes in pricing and production assumptions averaging about 37 per cent except when real prices are decreasing where it falls to 26 per cent. Unquestionably the private sector incurs the majority of the risks with their net revenue share ranging from -101.0 per cent in the decreasing real price case to some 17 per cent in the increasing real prices case.

The social supply cost of this oil ranges between $140.85 per cubic metre ($22.37 per barrel) and $189.12 per cubic metre ($30.05 per barrel) while the private supply cost ranges from $188.19 per cubic metre ($29.90 per barrel) to $388.94 per cubic metre ($61.81 per barrel). The low social supply cost shows that the project is worthwhile from a social viewpoint because the cost of this oil is far below the wellhead price. The existing fiscal regime, however, makes the project only marginally attractive to the private sector.

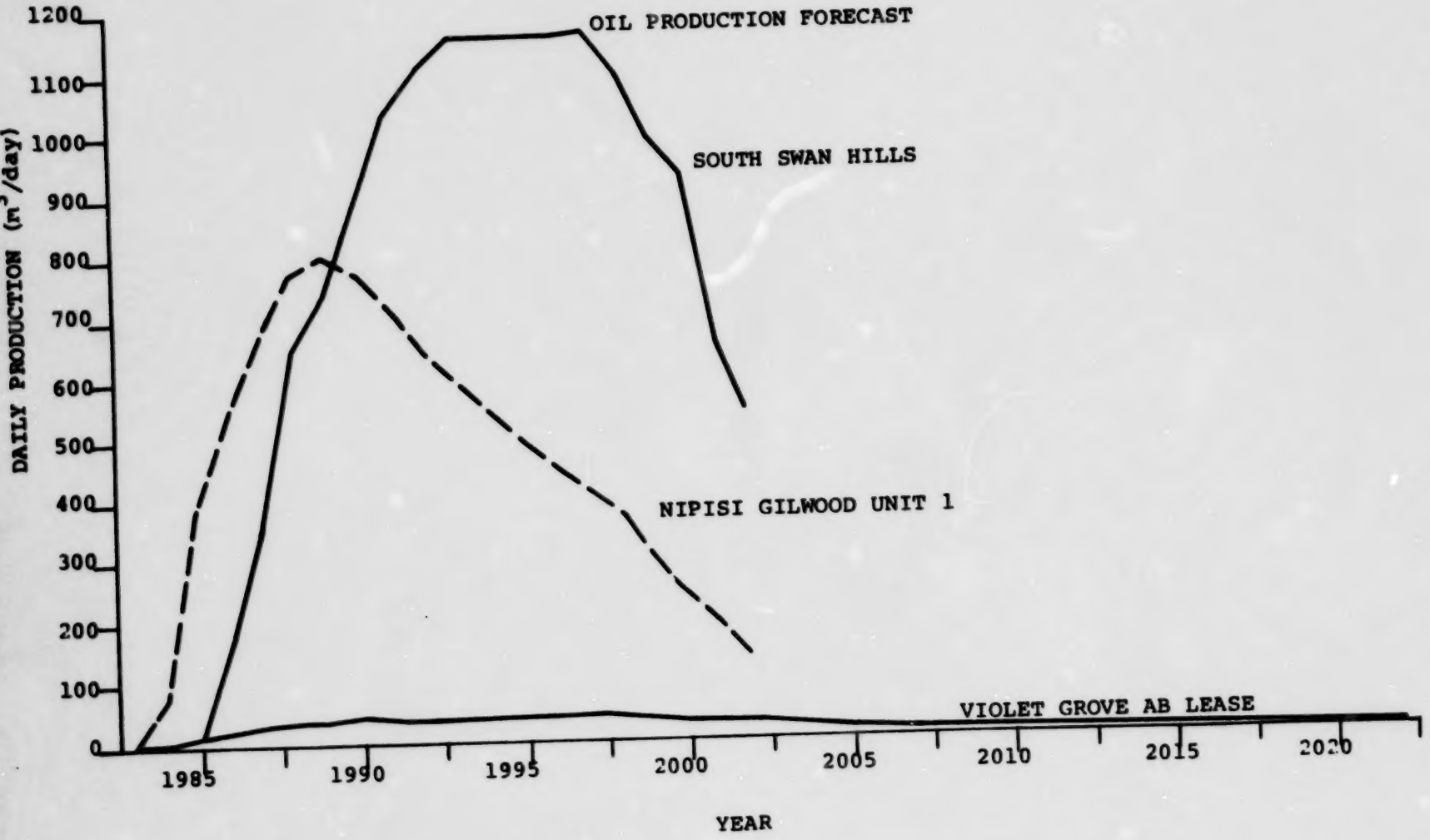
Overall the project is estimated to be economic at a 10 per cent discount rate in the unrisked base case, when real prices are

increasing and when incremental recovery increases. Under the remainder of the pricing and production assumptions the project does not realize a 10 per cent rate of return in the private perspective.

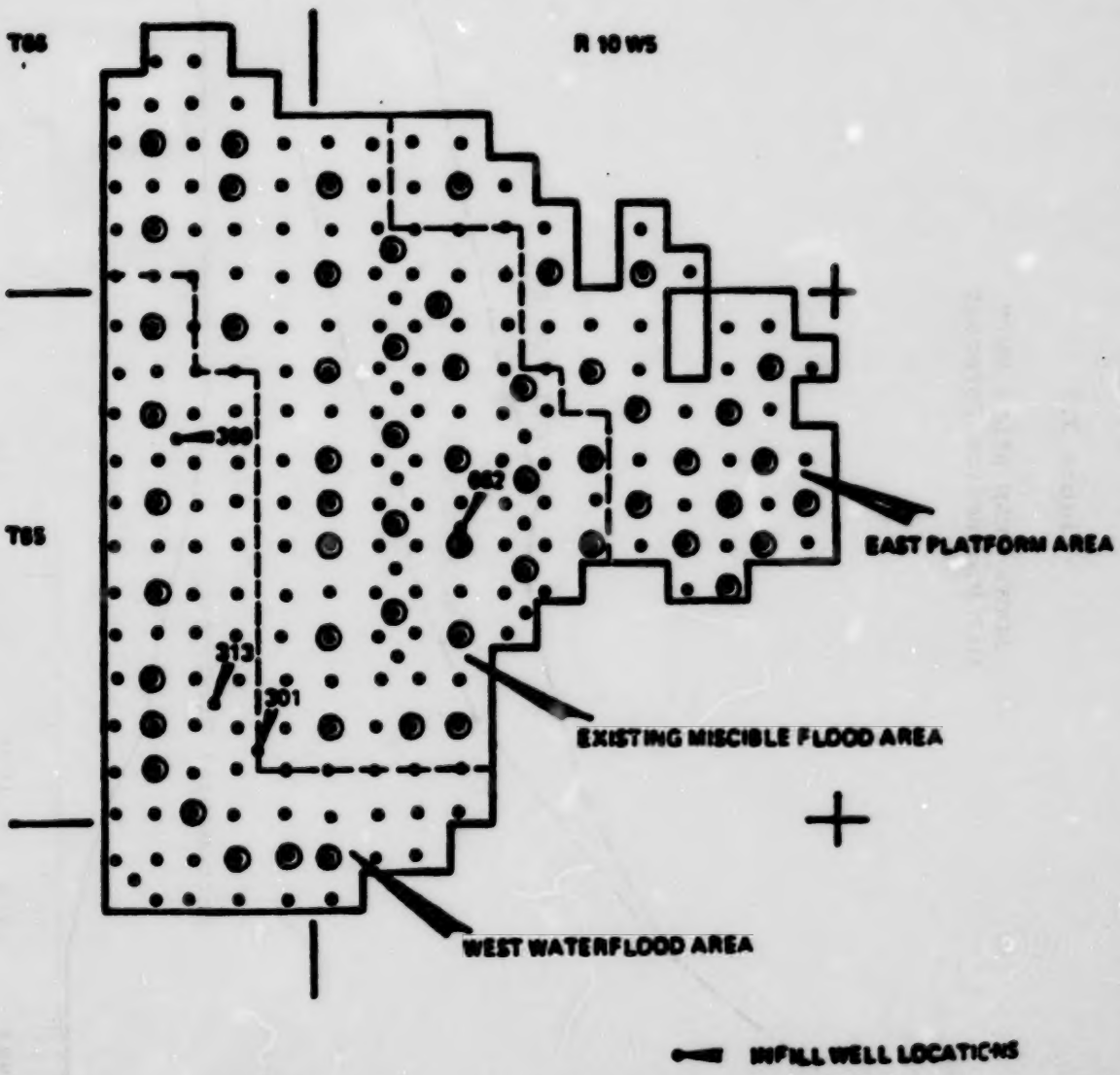
TABLES AND FIGURES

Figure 1.1

CONVENTIONAL LIGHT OIL EOR PROJECTS



South Swan Hills Unit



Source: Application for Miscible Flood Project Approval, South Swan Hills Unit, West Waterflood Area

Figure 3.1

SOUTH SWAN HILLS UNIT
Oil Production Forecast

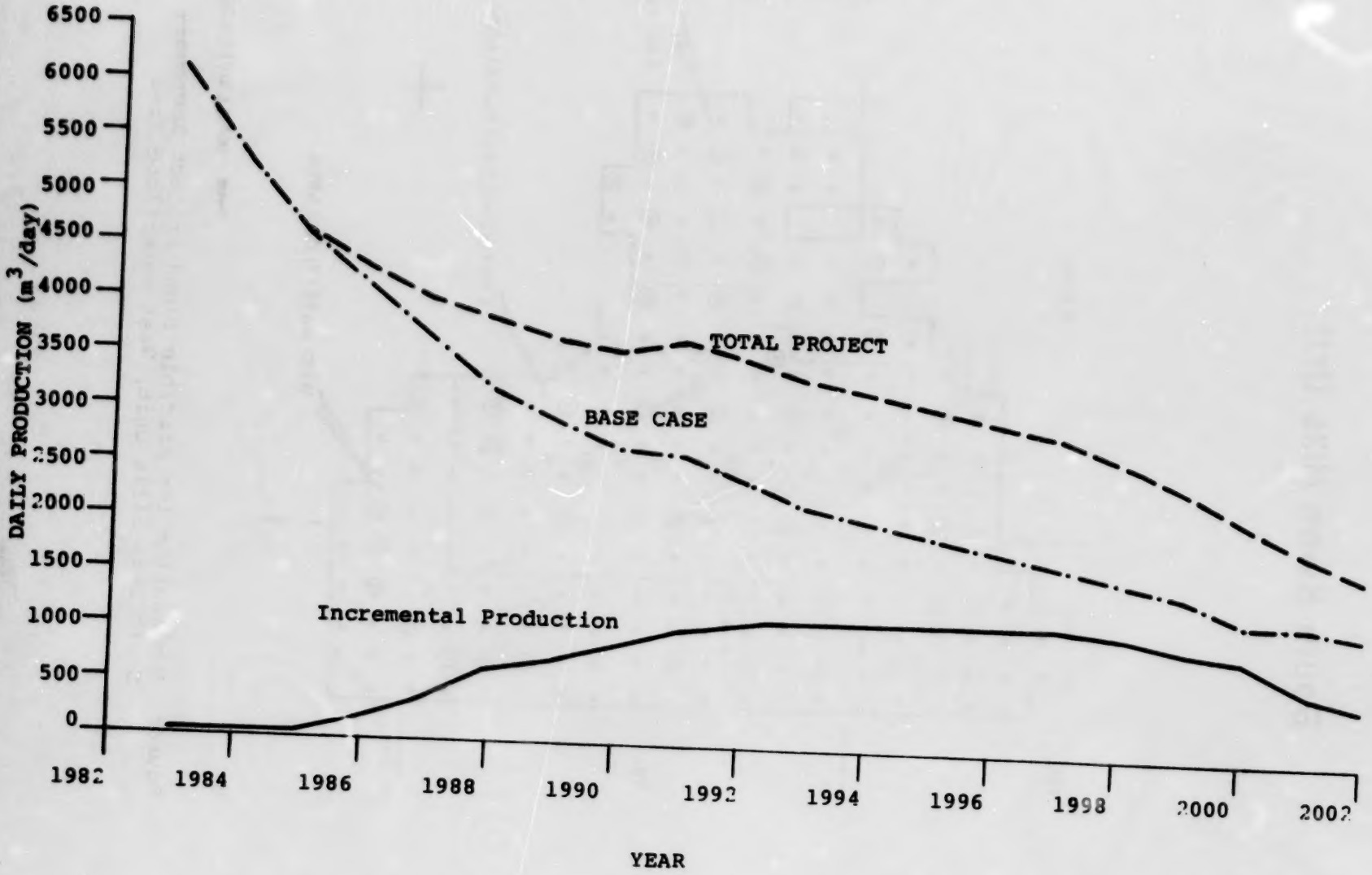


Figure 4.1

NIPISI GILWOOD UNIT 1
Oil Production Forecast

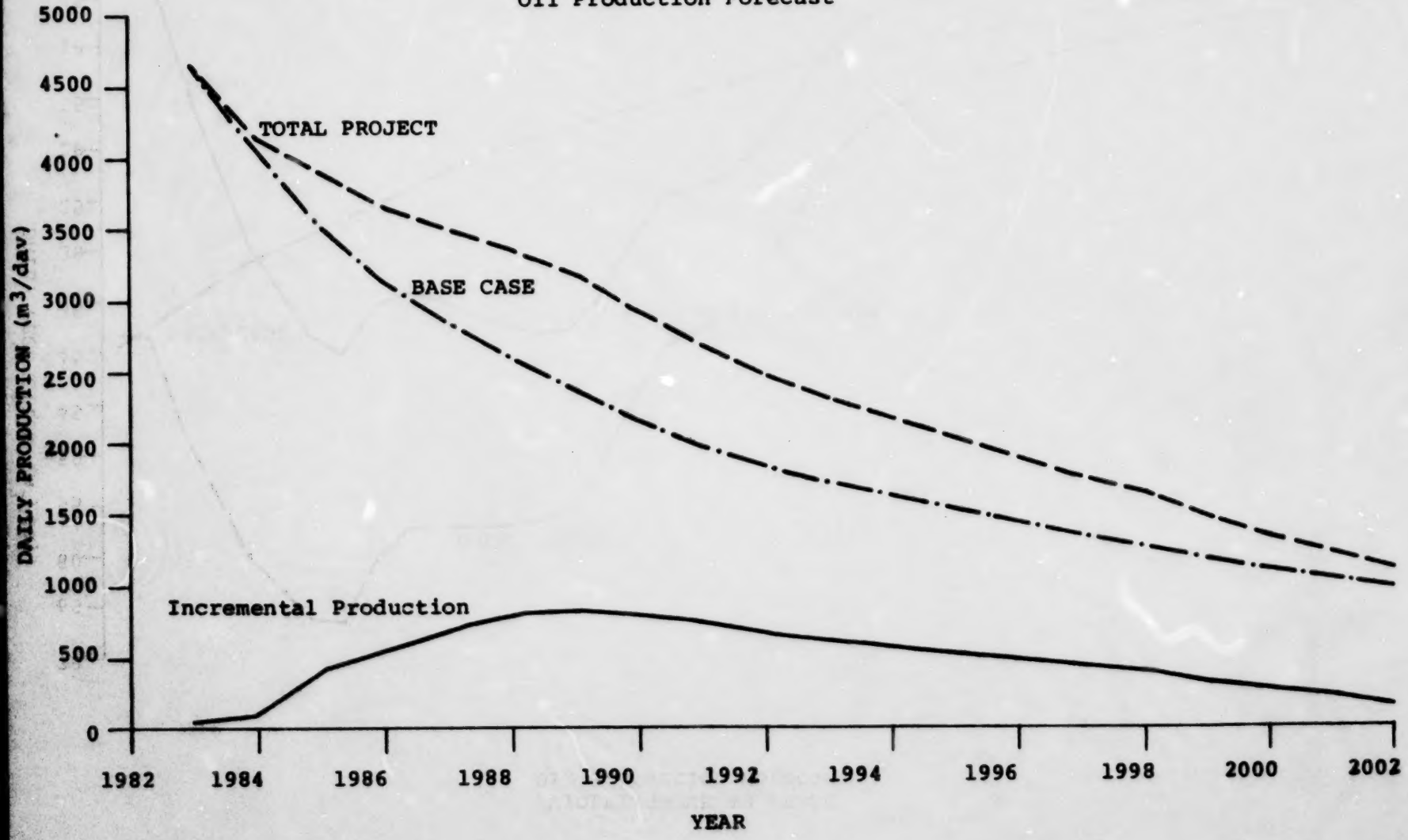


Figure 5.1

VIOLET GROVE AB LEASE
Oil Production Forecast

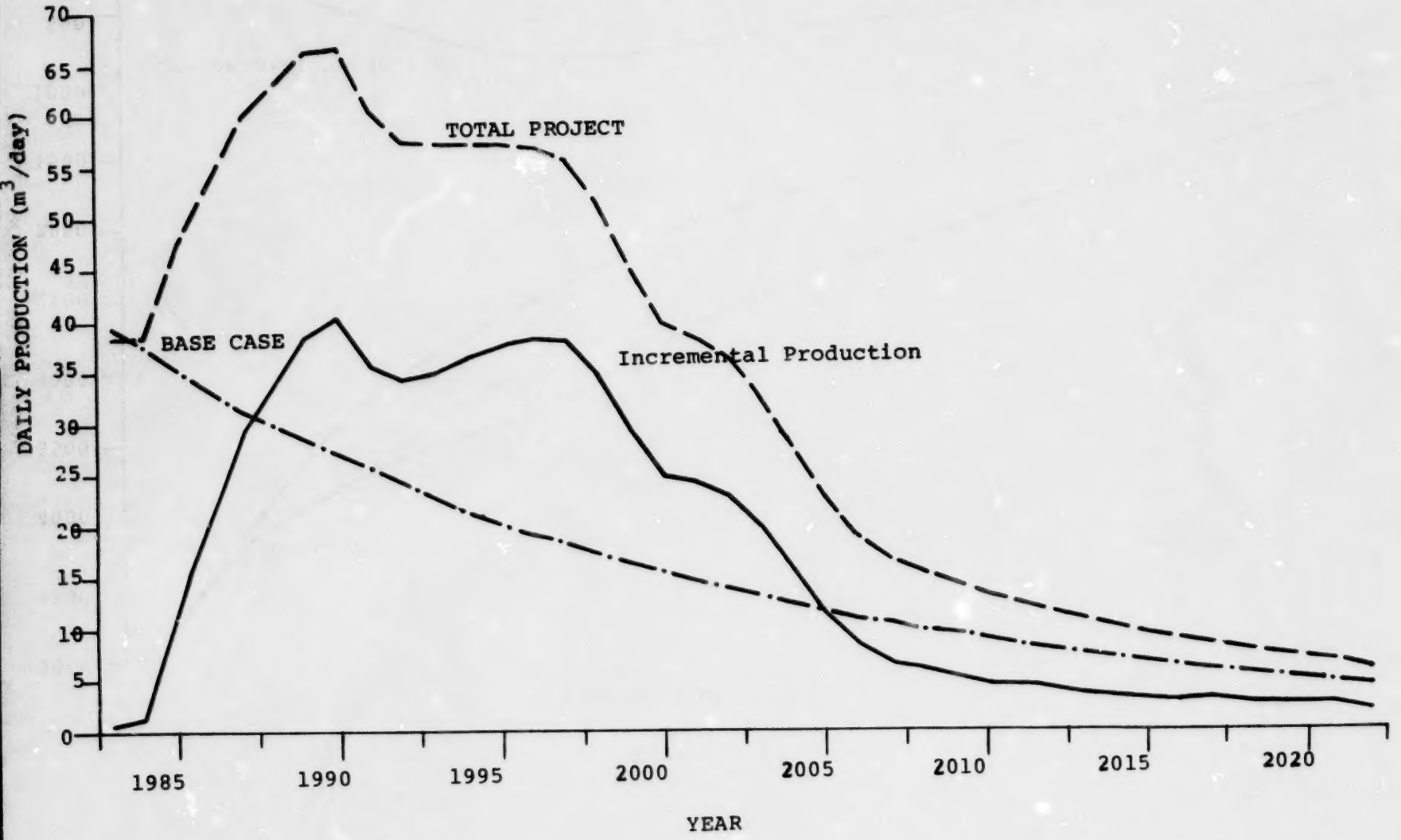


Table 1.1

RESERVOIR PROPERTIES

Reservoir Property	South Swan Hills	Nipisi Gilwood Unit 1	Violet Grove AB Lease
Rock Type	Carbonate	Sandstone	Sandstone
EOR Process	Hydrocarbon Miscible Flood	Hydrocarbon Miscible Flood	Hydrocarbon Miscible Flood
OOIP, $10^6 m^3$	142.8	114.0	1,180
OOIP in Project Area, $10^6 m^3$	40.7	12.4	1.81
Est. Rec. EOR Reserves, $10^6 m^3$	7.25	2.73	0.27
Project Life, years	20	20	40
Pattern	Inverted 9-spot	Inverted 9-spot	5-spot
Project Area, acres	11,000	3,840	640
Pattern Size, acres	640	640	80
Well Spacing, acres	160	160	40
Total Producer Wells	190	199	8
Year of Discovery	1959	1965	1953

Table 1.2

NET PRESENT VALUE REVENUE
IN MILLIONS OF 1983 DOLLARS

Real Discount Rate	South Swan Hills		Nipisi Gilwood Unit 1		Violet Grove AB Lease	
Unrisked Base Case - Constant Real Prices	w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties
5%	700.08	105.52	.37	57.68	20.05	3.21
7%	549.45	82.74	295.70	48.39	14.31	1.80
10%	383.83	57.74	224.24	37.68	8.39	0.42
15%	210.92	31.68	145.08	25.56	2.72	-0.79
Increasing Real Prices						
5%	1229.13	186.86	595.40	91.21	46.35	10.36
7%	965.52	146.80	488.56	75.55	33.78	6.87
10%	679.01	103.35	368.61	57.86	21.34	3.62
15%	384.83	58.81	237.58	38.44	9.93	0.87
Decreasing Real Prices						
5%	397.95	58.79	209.15	36.79	6.92	0.04
7%	308.39	45.32	172.25	31.16	4.11	-0.59
10%	209.06	30.41	129.75	24.54	1.17	-1.20
15%	104.24	14.72	82.14	16.83	-1.63	-1.72
Oil Prices Deregulated						
5%	690.52	52.96	415.04	59.61	19.37	2.60
7%	534.74	36.12	343.38	48.38	13.64	1.23
10%	364.29	18.30	261.45	35.57	7.75	-0.10
15%	187.99	0.92	170.40	21.36	2.12	-1.26
Increase in Incremental Recovery						
5%	857.59	161.48	430.60	67.36	25.53	4.39
7%	680.15	130.28	357.45	56.72	18.77	2.76
10%	484.50	95.67	273.79	44.44	11.77	1.15
15%	279.10	58.93	180.66	30.51	4.99	-0.29
Decrease in Incremental Recovery						
5%	542.46	71.73	313.59	48.21	14.37	1.97
7%	418.17	54.26	234.30	40.24	9.69	0.91
10%	282.11	35.26	174.94	31.07	4.89	-0.33
15%	141.28	15.82	109.66	20.72	0.39	-1.29

Table 1.3

NET PRESENT VALUE REVENUE SHARES
AT A 10 PER CENT DISCOUNT RATE
IN MILLIONS OF 1983 DOLLARS
(% of TOTAL NPV)

Project	Net Revenue	Provincial Government	Federal Government	Company
Unrisked Base Case - Constant Real Prices				
South Swan Hills	383.83	177.77 (46.31%)	148.30 (38.64%)	57.74 (15.04%)
Nipisi Gilwood Unit 1	224.24	100.69 (44.90%)	85.86 (38.29%)	37.68 (16.80%)
Violet Grove AB Lease	8.38	4.84 (57.76%)	3.12 (37.23%)	0.42 (5.01%)
Increasing Real Prices				
South Swan Hills	679.01	312.22 (45.98%)	263.43 (38.80%)	103.36 (15.22%)
Nipisi Gilwood Unit 1	368.31	168.40 (45.72%)	142.06 (38.57%)	57.86 (15.71%)
Violet Grove AB Lease	21.34	9.59 (44.91%)	8.15 (38.16%)	3.62 (16.93%)
Decreasing Real Prices				
South Swan Hills	209.06	98.50 (47.12%)	80.15 (38.34%)	30.41 (14.54%)
Nipisi Gilwood Unit 1	129.78	56.23 (43.34%)	49.03 (37.79%)	24.54 (18.91%)
Violet Grove AB Lease	1.17	2.05 (175.20%)	0.31 (26.00%)	-1.20 (-101.20%)

Table 1.3 (cont'd)

Project	Net Revenue	Provincial Government	Federal Government	Company
Deregulated Oil Prices				
South Swan Hills	364.29	205.30 (56.36%)	140.68 (38.62%)	18.30 (5.02%)
Nipisi Gilwood Unit 1	261.45	125.51 (48.01%)	100.38 (38.39%)	35.57 (13.60%)
Violet Grove AB Lease	7.75	4.99 (64.39%)	2.86 (36.90%)	-0.10 (-1.29%)
Increasing Incremental Recovery				
South Swan Hills	484.50	212.68 (43.90%)	176.12 (36.35%)	95.67 (19.75%)
Nipisi Gilwood Unit 1	272.91	123.63 (45.30%)	104.84 (38.42%)	44.44 (16.28%)
Violet Grove AB Lease	11.77	6.18 (52.51%)	4.44 (37.72%)	1.15 (9.77%)
Decreasing Incremental Recovery				
South Swan Hills	282.11	138.20 (48.99%)	108.63 (38.51%)	35.26 (12.50%)
Nipisi Gilwood Unit 1	175.82	77.77 (44.23%)	66.98 (38.10%)	31.07 (17.67%)
Violet Grove AB Lease	4.89	3.45 (70.55%)	1.77 (36.20%)	-0.33 (-6.75%)

Table 1.4

UNRISKED BASE CASE REAL SUPPLY COSTS
AT A 10 PER CENT DISCOUNT RATE
in $/m^3
($/bbl)

Project	Social Supply Cost	Private Supply Cost	Effective Wellhead Price
South Swan Hills	124.85 (19.84)	160.29 (25.47)	271.22 (43.10)
Nipisi Gilwood Unit 1	99.26 (15.77)	206.71 (32.85)	229.69 (36.50)
Violet Grove AB Lease	161.30 (25.63)	261.24 (41.51)	267.14 (42.45)

Table 3.1

SOUTH SWAN HILLS
NET PRESENT VALUE REVENUES
IN MILLIONS OF 1983 DOLLARS

Real Discount Rate	Constant Real Prices*		Increasing Real Prices		Decreasing Real Prices	
	w/o taxes royalties	w/ taxes royalties	w/o taxes royalties	w/ taxes royalties	w/o taxes royalties	w/ taxes royalties
5%	700.08	105.52	1229.13	186.86	397.95	58.79
7%	549.45	82.74	965.52	146.80	308.39	45.32
10%	383.83	57.74	679.01	103.35	209.06	30.41
15%	210.92	31.68	384.83	58.81	104.24	14.72

Oil Prices** Deregulated		Increase in Incremental Recovery		Decrease in Incremental Recovery	
w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties
690.52	52.96	857.59	161.48	542.46	71.73
534.74	36.12	680.15	130.28	418.17	54.26
364.29	18.30	484.50	95.67	282.11	35.26
187.99	0.92	279.10	58.93	141.28	15.82

* The Constant Real Price Case is the unrisked base case scenario.

** All production is assumed to pay NORP royalties.

Table 3.2

SOUTH SWAN HILLS
NET PRESENT VALUE REVENUE CALCULATION
10 PER CENT DISCOUNT RATE
IN MILLIONS OF 1983 DOLLARS

Unrisked Base Case - Constant Real Prices			
Gross Revenue:		687.30	
less:	Operating Costs		287.11
	Capital Costs		16.36
	Royalties		152.13
	Provincial Income Tax		25.64
	Federal Income Tax		101.93
	PGRT		46.37
Net Present Value		57.74	
Increasing Real Prices			
Gross Revenue:		982.47	
less:	Operating Costs		287.11
	Capital Costs		16.36
	Royalties		266.72
	Provincial Income Tax		45.50
	Federal Income Tax		181.63
	PGRT		81.80
Net Present Value		103.35	
Decreasing Real Prices			
Gross Revenue:		512.52	
less:	Operating Costs		287.11
	Capital Costs		16.36
	Royalties		84.66
	Provincial Income Tax		13.84
	Federal Income Tax		54.75
	PGRT		25.40
Net Present Value		30.41	

Table 3.2 (cont'd)

Oil Prices Deregulated		
Gross Revenue:	667.75	
less: Operating Costs		287.11
Capital Costs		16.36
Royalties		185.47
Provincial Income Tax		19.83
Federal Income Tax		96.66
PGRT		44.02
Net Present Value	18.30	
Increase in Incremental Recovery		
Gross Revenue:	787.96	
less: Operating Costs		287.11
Capital Costs		16.36
Royalties		182.53
Provincial Income Tax		30.10
Federal Income Tax		117.67
PGRT		58.45
Net Present Value	95.74	
Decrease in Incremental Recovery		
Gross Revenue:	585.57	
less: Operating Costs		287.11
Capital Costs		16.36
Royalties		120.24
Provincial Income Tax		17.96
Federal Income Tax		74.47
PGRT		34.16
Net Present Value	35.26	

Table 3.3

SOUTH SWAN HILLS
NET PRESENT VALUE REVENUE SHARES
IN MILLIONS OF 1983 DOLLARS
(% of Total NPV)

Unrisked Base Case
Constant Real Price

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	700.08	323.32 (46.18%)	271.24 (38.74%)	105.52 (15.08%)
7%	549.45	254.03 (46.23%)	212.67 (38.70%)	82.74 (15.07%)
10%	383.83	177.77 (46.31%)	148.30 (38.64%)	57.74 (15.04%)
15%	210.92	98.05 (46.49%)	81.20 (38.50%)	31.68 (15.01%)

Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	1229.13	564.69 (45.94%)	477.57 (38.85%)	187.87 (15.21%)
7%	965.52	443.78 (45.96%)	374.94 (38.83%)	146.80 (15.21%)
10%	679.01	312.22 (45.98%)	263.43 (38.80%)	103.36 (15.22%)
15%	384.83	177.01 (46.00%)	149.01 (38.72%)	58.81 (15.28%)

Table 3.3 (cont'd)

Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	397.95	185.75 (46.68%)	153.42 (38.55%)	58.79 (14.77%)
7%	308.39	144.42 (46.83%)	118.65 (38.47%)	45.32 (14.7%)
10%	209.06	98.50 (47.12%)	80.15 (38.34%)	30.41 (14.54%)
15%	104.24	49.93 (47.90%)	39.58 (37.97%)	14.72 (14.13%)

Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	690.52	370.04 (53.59%)	267.51 (38.74%)	52.96 (7.67%)
7%	534.74	291.68 (54.55%)	206.94 (38.70%)	36.12 (6.75%)
10%	364.29	205.30 (56.36%)	140.68 (38.62%)	18.30 (5.02%)
15%	187.99	114.82 (61.08%)	72.25 (38.43%)	0.92 (.49%)

Table 3.3 (con't)

Increase in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	857.59	379.66 (44.27%)	316.46 (36.90%)	161.48 (18.30%)
7%	680.15	300.22 (44.14%)	249.65 (36.70%)	130.28 (19.16%)
10%	484.50	212.68 (43.90%)	176.12 (36.35%)	95.67 (19.75%)
15%	279.10	120.91 (43.32%)	99.26 (35.57%)	58.93 (21.11%)

Decrease in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	542.46	260.98 (48.11%)	209.77 (38.67%)	71.73 (13.22%)
7%	418.17	202.44 (48.41%)	161.48 (38.62%)	54.26 (12.97%)
10%	282.11	138.20 (48.99%)	108.63 (38.51%)	35.26 (12.50%)
15%	141.28	71.43 (50.56%)	54.04 (38.25%)	15.82 (11.19%)

Table 3.4

SOUTH SWAN HILLS
REAL SUPPLY COSTS
10 PER CENT REAL DISCOUNT RATE
IN 1983 DOLLARS $/m^3
($/bbl)

Sensitivity Scenario	Social Supply Cost	Private Supply Cost	Effective Wellhead Price
Unrisked Base Case - Constant Real Prices	124.85 (19.84)	160.29 (25.47)	271.22 (43.09)
Increasing Real Prices	136.90 (21.75)	174.94 (27.80)	438.70 (69.71)
Decreasing Real Prices	111.23 (17.67)	156.43 (24.86)	172.06 (27.34)
Oil Prices Deregulated	126.95 (20.17)	256.49 (40.76)	260.13 (41.34)
Increase in Incremental Recovery	112.23 (17.83)	251.03 (39.89)	286.72 (45.56)
Decrease in Incremental Recovery	142.24 (22.60)	237.44 (37.73)	252.22 (40.07)

Table 4.1

NIPISI GILWOOD UNIT 1
NET PRESENT VALUE REVENUES
IN MILLIONS OF 1983 DOLLARS

Real Discount Rate	Constant Real Prices*		Increasing Real Prices		Decreasing Real Prices	
	w/o taxes royalties	w/ taxes royalties	w/o taxes royalties	w/ taxes royalties	w/o taxes royalties	w/ taxes royalties
5%	358.37	57.68	595.40	91.21	209.15	36.29
7%	295.70	48.39	488.56	75.55	172.25	31.16
10%	224.24	37.68	368.31	57.86	129.75	24.54
15%	145.08	25.56	237.58	38.44	82.14	16.83

Oil Prices Deregulated**		Increase in Incremental Recovery		Decrease in Incremental Recovery	
w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties
415.04	59.61	429.46	67.36	287.72	48.21
343.38	48.38	356.43	56.72	235.32	40.24
261.45	35.57	272.91	44.44	175.82	31.07
170.40	21.36	179.94	30.51	110.38	20.72

* The Constant Real Price Case is the unrisked base case scenario.

** All production is assumed to pay NORP royalties.

Table 4.2

NIPISI GILWOOD UNIT 1
NET PRESENT VALUE REVENUE CALCULATION
10 PER CENT REAL DISCOUNT RATE
IN MILLIONS OF 1983 DOLLARS

Unrisked Base Case - Constant Real Prices			
Gross Revenue		377.56	
Less:	Operating Costs		138.78
	Capital Costs		14.55
	Royalties		85.40
	Provincial Income Tax		15.29
	Federal Income Tax		58.95
	PGRT		26.91
Net Present Value		37.68	
Increasing Real Prices			
Gross Revenue		521.63	
Less:	Operating Costs		138.78
	Capital Costs		14.55
	Royalties		143.67
	Provincial Income Tax		24.73
	Federal Income Tax		97.86
	PGRT		44.20
Net Present Value		57.84	
Decreasing Real Prices			
Gross Revenue		283.09	
Less:	Operating Costs		138.78
	Capital Costs		14.55
	Royalties		47.11
	Provincial Income Tax		9.12
	Federal Income Tax		33.42
	PGRT		15.85
Net Present Value		24.54	

Table 4.2 (cont'd)

Oil Prices Deregulated			
Gross Revenue		414.78	
Less:	Operating Costs		138.78
	Capital Costs		14.55
	Royalties		108.68
	Provincial Income Tax		16.82
	Federal Income Tax		69.00
	PGRT		31.38
Net Present Value		35.57	
Increase in Incremental Recovery			
Gross Revenue		427.12	
Less:	Operating Costs		138.78
	Capital Costs		14.55
	Royalties		105.16
	Provincial Income Tax		18.47
	Federal Income Tax		72.09
	PGRT		32.75
Net Present Value		45.32	
Decrease in Incremental Recovery			
Gross Revenue		328.26	
Less:	Operating Costs		138.78
	Capital Costs		14.55
	Royalties		65.63
	Provincial Income Tax		12.14
	Federal Income Tax		45.88
	PGRT		21.10
Net Present Value		30.18	

Table 4.3

NIPISI GILWOOD UNIT 1
NET PRESENT VALUE REVENUE SHARES
IN MILLIONS OF 1983 DOLLARS
(% of Total NPV)

Unrisked Base Case
Constant Real Price

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	358.37	162.86 (45.44%)	137.84 (38.46%)	57.68 (16.10%)
7%	295.70	133.76 (45.24%)	113.54 (38.40%)	48.39 (16.36%)
10%	224.24	100.69 (44.90%)	85.86 (38.29%)	37.68 (16.80%)
15%	145.08	64.25 (44.29%)	55.25 (38.08%)	25.56 (17.62%)

Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	595.40	273.90 (46.00%)	230.28 (38.68%)	91.21 (15.32%)
7%	488.56	224.24 (45.90%)	188.76 (38.64%)	75.55 (15.46%)
10%	368.31	168.40 (45.72%)	142.06 (38.57%)	57.86 (15.71%)
15%	237.58	107.81 (45.38%)	91.32 (38.44%)	38.44 (16.18%)

Table 4.3 (cont'd)

Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	209.15	92.71 (44.33%)	79.65 (38.08%)	36.79 (17.59%)
7%	172.25	75.69 (43.94%)	65.40 (37.97%)	31.16 (18.09)
10%	129.75	56.23 (43.34%)	49.03 (37.79%)	24.54 (18.91%)
15%	82.14	34.61 (42.14%)	30.71 (37.38%)	16.83 (20.48%)

Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	415.04	195.49 (47.10%)	159.96 (38.54%)	59.61 (14.36%)
7%	343.38	162.84 (47.42%)	132.15 (38.40%)	48.38 (14.09%)
10%	261.45	125.51 (48.01%)	100.38 (38.39%)	35.57 (13.60%)
15%	170.40	83.92 (49.25%)	65.12 (38.22%)	21.36 (12.53%)

Table 4.3 (con't)

Increase in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	429.46	196.54 (45.76%)	165.57 (38.55%)	67.36 (15.68%)
7%	356.43	162.48 (45.59%)	137.23 (38.50%)	56.72 (15.91%)
10%	272.91	123.63 (45.30%)	104.84 (38.42%)	44.44 (16.28%)
15%	179.94	80.57 (44.78%)	68.84 (38.26%)	30.51 (16.96%)

Decrease in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	287.72	129.23 (44.92%)	110.29 (38.33%)	48.21 (16.75%)
7%	235.32	105.09 (44.66%)	90.00 (38.24%)	40.24 (17.10%)
10%	175.82	77.77 (44.23%)	66.98 (38.10%)	31.07 (17.67%)
15%	110.38	47.93 (43.42%)	41.72 (37.80%)	20.72 (18.78%)

Table 4.4

NIPISI GILWOOD UNIT 1
REAL SUPPLY COSTS
10 PER CENT REAL DISCOUNT RATE
IN 1983 DOLLARS $/m^3
($/bbl)

Sensitivity Scenario	Social Supply Cost	Private Supply Cost	Effective Wellhead Price
Unrisked Base Case - Constant Real Prices	99.26 (15.77)	206.71 (32.85)	229.69 (36.50)
Increasing Real Prices	100.97 (16.04)	295.04 (46.88)	331.82 (52.73)
Decreasing Real Prices	96.39 (15.32)	148.79 (23.64)	162.72 (25.86)
Oil Prices Deregulated	100.82 (16.02	237.27 (37.70)	256.07 (40.69)
Increase in Incremental Recovery	86.69 (13.78)	206.42 (32.80)	230.40 (36.41)
Decrease in Incremental Recovery	116.35 (18.49)	207.56 (32.98)	229.14 (36.41)

Table 5.1

VIOLET GROVE AB LEASE
NET PRESENT VALUE REVENUES
IN MILLIONS OF 1983 DOLLARS
(% of Total NPV)

Real Discount Rate	Constant Real Prices*		Increasing Real Prices		Decreasing Real Prices	
	w/o taxes royal-ties	w/ taxes royal-ties	w/o taxes royal-ties	w/ taxes royal-ties	w/o taxes royal-ties	w/ taxes royal-ties
5%	20.05	3.21	46.35	10.36	6.92	0.04
7%	14.31	1.80	33.78	6.87	4.11	-0.59
10%	8.39	0.42	21.34	3.62	1.17	-1.20
15%	2.72	-0.79	9.93	.87	-1.63	-1.72

Oil Prices Deregulated**		Increase in Incremental Recovery		Decrease in Incremental Recovery	
w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties	w/o taxes & royalties	w/ taxes & royalties
19.37	2.60	25.53	4.39	14.37	1.97
13.64	1.23	18.77	2.76	9.69	0.91
7.75	-0.10	11.77	1.15	4.89	-0.33
2.12	-1.26	4.99	-0.29	0.39	-1.29

* The Constant Real Prices Case is the unrisked base case scenario.

** All production is assumed to pay NORP royalties.

Table 5.2

VIOLET GROVE AB LEASE
NET PRESENT VALUE REVENUE CALCULATION
10 PER CENT REAL DISCOUNT RATE IN
IN MILLIONS OF 1983 DOLLARS

Unrisked Base Case - Constant Real Prices			
Gross Revenue		21.34	
Less:	Operating Costs		10.24
	Capital Costs		2.73
	Royalties		4.37
	Provincial Income Tax		0.47
	Federal Income Tax		1.98
	PGRT		1.14
Net Present Value		0.42	
Increasing Real Prices			
Gross Revenue		34.31	
Less:	Operating Costs		10.24
	Capital Costs		2.73
	Royalties		8.11
	Provincial Income Tax		1.48
	Federal Income Tax		5.86
	PGRT		2.69
Net Present Value		3.62	
Decreasing Real Prices			
Gross Revenue		14.14	
Less:	Operating Costs		10.24
	Capital Costs		2.73
	Royalties		2.13
	Provincial Income Tax		-0.08
	Federal Income Tax		0.03
	PGRT		0.28
Net Present Value		-1.20	

Table 5.2 (cont'd)

Oil Prices Deregulated		
Gross Revenue	20.72	
Less: Operating Costs		10.24
Capital Costs		2.73
Royalties		4.62
Provincial Income Tax		0.37
Federal Income Tax		1.81
PGRT		1.05
Net Present Value	0.10	
Increase in Incremental Recovery		
Gross Revenue	24.77	
Less: Operating Costs		10.28
Capital Costs		2.73
Royalties		5.46
Provincial Income Tax		0.72
Federal Income Tax		2.90
PGRT		1.54
Net Present Value	1.15	
Decrease in Incremental Recovery		
Gross Revenue	17.80	
Less: Operating Costs		10.19
Capital Costs		2.73
Royalties		3.24
Provincial Income Tax		0.21
Federal Income Tax		1.04
PGRT		0.73
Net Present Value	0.33	

Table 5.3

VIOLET GROVE AB LEASE
NET PRESENT VALUE REVENUE SHARES
IN MILLIONS OF 1983 DOLLARS
(% of Total NPV)

Unrisked Base Case
Constant Real Price

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	20.05	9.26 (46.18%)	7.60 (37.91%)	3.21 (16.01%)
7%	14.31	7.12 (49.78%)	5.38 (37.62%)	1.80 (12.60%)
10%	8.38	4.84 (57.76%)	3.12 (37.23%)	0.42 (5.01%)
15%	2.72	2.52 (92.65%)	0.97 (35.66%)	-0.79 (-28.31%)

Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	46.35	18.19 (39.24%)	17.80 (38.40%)	10.36 (22.36%)
7%	33.78	13.96 (41.33%)	12.95 (38.34%)	6.87 (20.33%)
10%	21.34	9.59 (44.91%)	8.15 (38.16%)	3.62 (16.93%)
15%	9.93	5.30 (53.37%)	3.76 (37.86%)	-0.87 (8.77%)

Table 5.3 (cont'd)

Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	6.92	4.40 (63.58%)	2.48 (35.84%)	0.04 (0.58%)
7%	4.11	3.26 (79.32%)	1.41 (34.30%)	-0.59 (-13.62%)
10%	1.17	2.05 (175.20%)	0.31 (26.00%)	-1.20 (-201.20)
15%	-1.63	0.81 (-48.56%)	-0.71 (43.56%)	-1.72 (105.00%)

Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	19.37	9.46 (48.84%)	7.30 (37.69%)	2.60 (13.47%)
7%	13.64	7.30 (53.52%)	5.11 (37.46%)	1.23 (9.02%)
10%	7.75	4.99 (64.39%)	2.86 (36.90%)	-0.10 (-1.29%)
15%	2.12	2.66 (125.47%)	0.74 (34.90%)	-1.26 (-60.37%)

Table 5.3 (con't)

Increase in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	25.53	11.42 (44.73%)	9.72 (38.07%)	4.39 (17.20%)
7%	18.77	8.89 (47.36%)	7.12 (37.93%)	2.76 (14.71%)
10%	11.77	6.18 (52.51%)	4.44 (37.72%)	1.15 (9.77%)
15%	4.99	3.42 (68.54%)	1.86 (37.27%)	-0.29 (-5.81%)

Decrease in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	14.37	7.02 (48.85%)	5.38 (37.44%)	1.97 (13.71%)
7%	9.69	5.29 (54.59%)	3.59 (37.05%)	0.81 (0.81%)
10%	4.89	3.45 (70.55%)	1.77 (36.20%)	-0.33 (-6.75%)
15%	0.39	1.60 (41.02%)	0.07 (17.95%)	-1.29 (-328.15%)

Table 5.4

VIOLET GROVE AB LEASE
REAL SUPPLY COSTS
10 PER CENT REAL DISCOUNT RATE
IN 1983 DOLLARS $/m^3
($/bbl)

Sensitivity Scenario	Social Supply Cost	Private Supply Cost	Effective Wellhead Price
Unrisked Base Case - Constant Real Prices	161.30 (25.63)	261.24 (41.51)	267.14 (42.45)
Increasing Real Prices	163.60 (26.00)	388.94 (61.81)	434.85 (69.10)
Decreasing Real Prices	158.46 (25.18)	188.19 (29.90)	173.86 (27.63)
Oil Prices Deregulated	161.72 (25.70)	260.01 (41.32)	259.00 (41.16)
Increase in Incremental Recovery	140.85 (22.37)	257.63 (40.94)	270.87 (43.04)
Decrease in Incremental Recovery	189.12 (30.05)	265.15 (42.13)	260.85 (41.45)

APPENDIX A

FISCAL REGIME AND SENSITIVITY SCENARIOS

Sensitivity Scenarios

All sensitivities were performed both with and without taxes and royalties included.

1. Unrisked Base Case - Constant Price Scenario[1]

   Assumptions:

   - All oil prices remain constant in real terms.
   - Constant real costs.
   - Evaluated at real discount rates of 5 per cent, 7 per cent, 10 per cent and 15 per cent.
   - annual inflation in 1983 is 8.8 per cent then 7.8, 7.2, 7.0, 7.3, 7.0, 6.9, 6.5, then 6.0 thereafter (forecast for 1983-87 is taken from the Economic Council's CANDIDE forecast, Nineteenth Annual Review).

2. Increasing Real Prices Case[2]

   Assumptions:

   - Same as 1 but prices increase by 5 per cent annually in real terms.

3. Decreasing Real Prices Case

   Assumptions:

   - Same as 1 but prices decrease by 5 per cent annually in real terms.

4. Oil Prices Deregulated Case

   Assumptions:

   - Same as 1 but oil prices are assumed to be deregulated (i.e., all oil production receives NORP) with quality differentials similar to the world market.

   - All production pays NORP royalties.

5. Increase in Incremental Recovery Case

   Assumptions:

   - Same as 1 but the tertiary recovery factor is increased by 15 per cent.

6. Decrease in Incremental Recovery Case

Assumptions:

- Same as 1 but the tertiary recovery factor is decreased by 15 per cent.

Fiscal Regime

1 Federal Income Tax Rate: 36 per cent.

2 Provincial Income Tax Rate: 11 per cent.

3 Petroleum Gas Revenue Tax (PGRT): 16 per cent on operating revenues (effectively 12 per cent)

PGRT Relief applies.

4 Resource Allowance: 25 per cent.

5 Depletion is earned at a rate of 33.3 per cent.

6 Investment Tax Credit (ITC) = 10 per cnt for expenditures on tangible assets except CEE.

7 Capital Cost Allowance (CCA)
a) Canadian Exploration Expenses (CEE): 100 per cent
b) Canadian Development Expenses (CDE): 30 per cent
c) Class 10: 30 per cent (drilling rigs and well equipment).

8 Alberta Royalty Rates.

9 All three projects qualify for royalty deduction under Section 4.2 of the Alberta Petroleum Royalty Regulations.

10 All three projects qualify for an NGL rebate under Section 4(3) of the Alberta Petroleum Royalty Regulations. However, the NGL rebate was not applied for purposes of the analyses.

Notes

1 The "Unrisked Base Case" is representative of the 100 per cent success case.

2 Real prices increase at a real rate of 5 per cent annually. While this assumption may appear to be unlikely it does not attempt to bracket an extreme limit for a range of future oil prices which at best are clouded in uncertainty. The fact that the results do not go through the roof suggests that without drastic price changes the interacting and offsetting features of the fiscal regime tend to mask the effect of rising prices. This price assumption is not presented as a forecast and should be considered as a tool that is used for analytical purposes only to see how the fiscal regime performs.

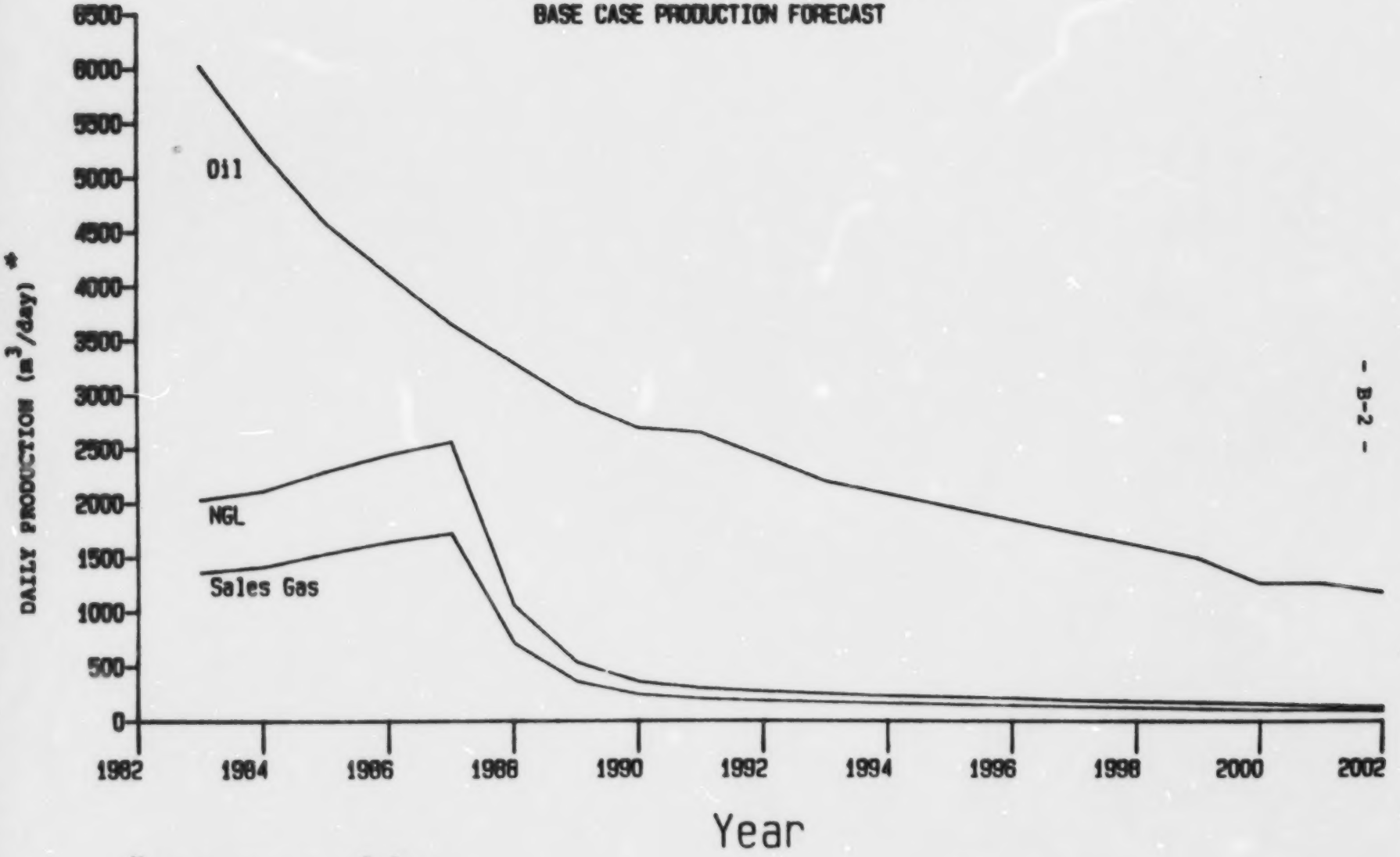
APPENDIX B

PRODUCTION PROFILES

Figure B1

South Swan Hills Unit

BASE CASE PRODUCTION FORECAST



* Sales Gas in $10^3 m^3$/day

Figure B2

South Swan Hills Unit

TOTAL PROJECT PRODUCTION FORECAST

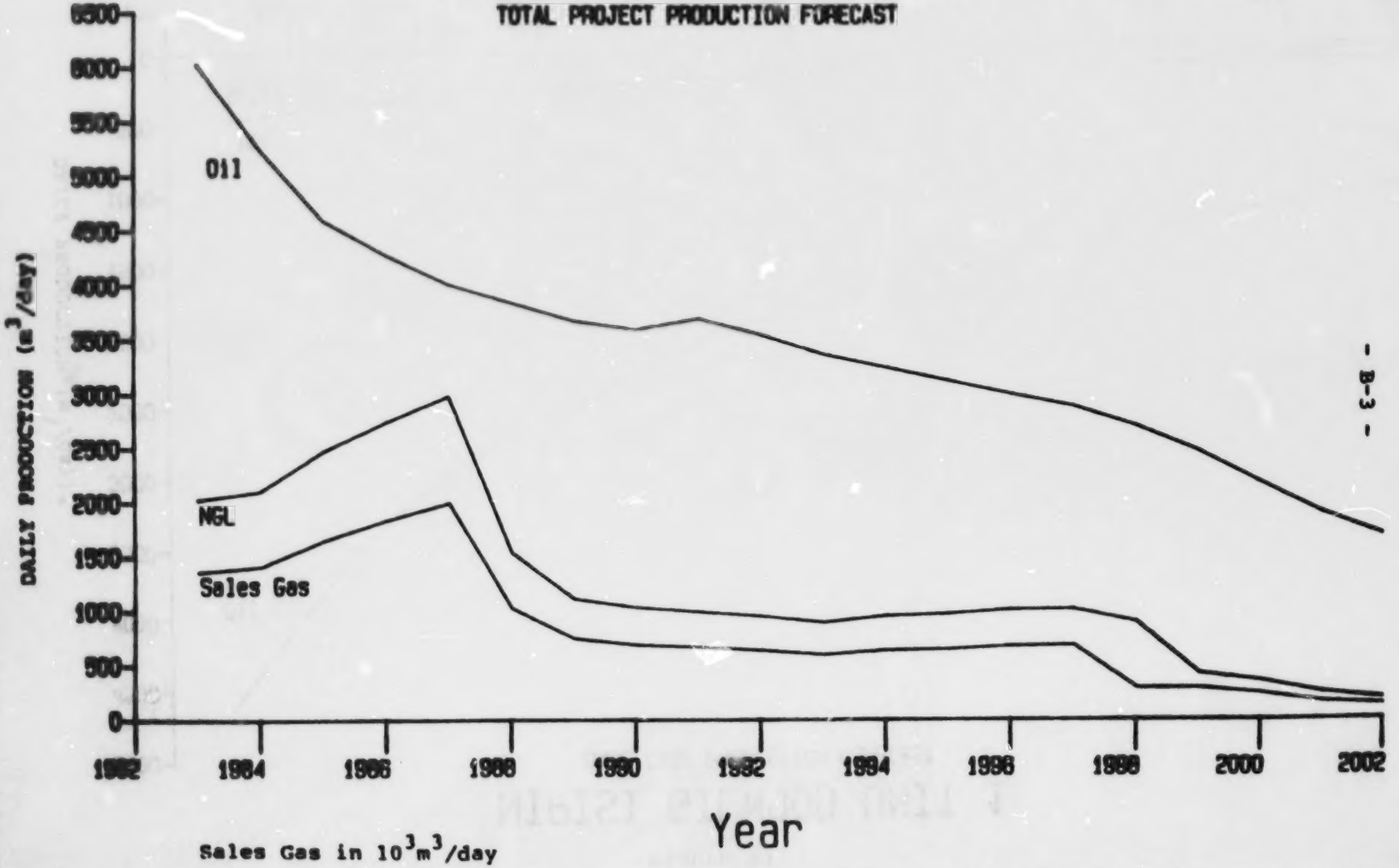
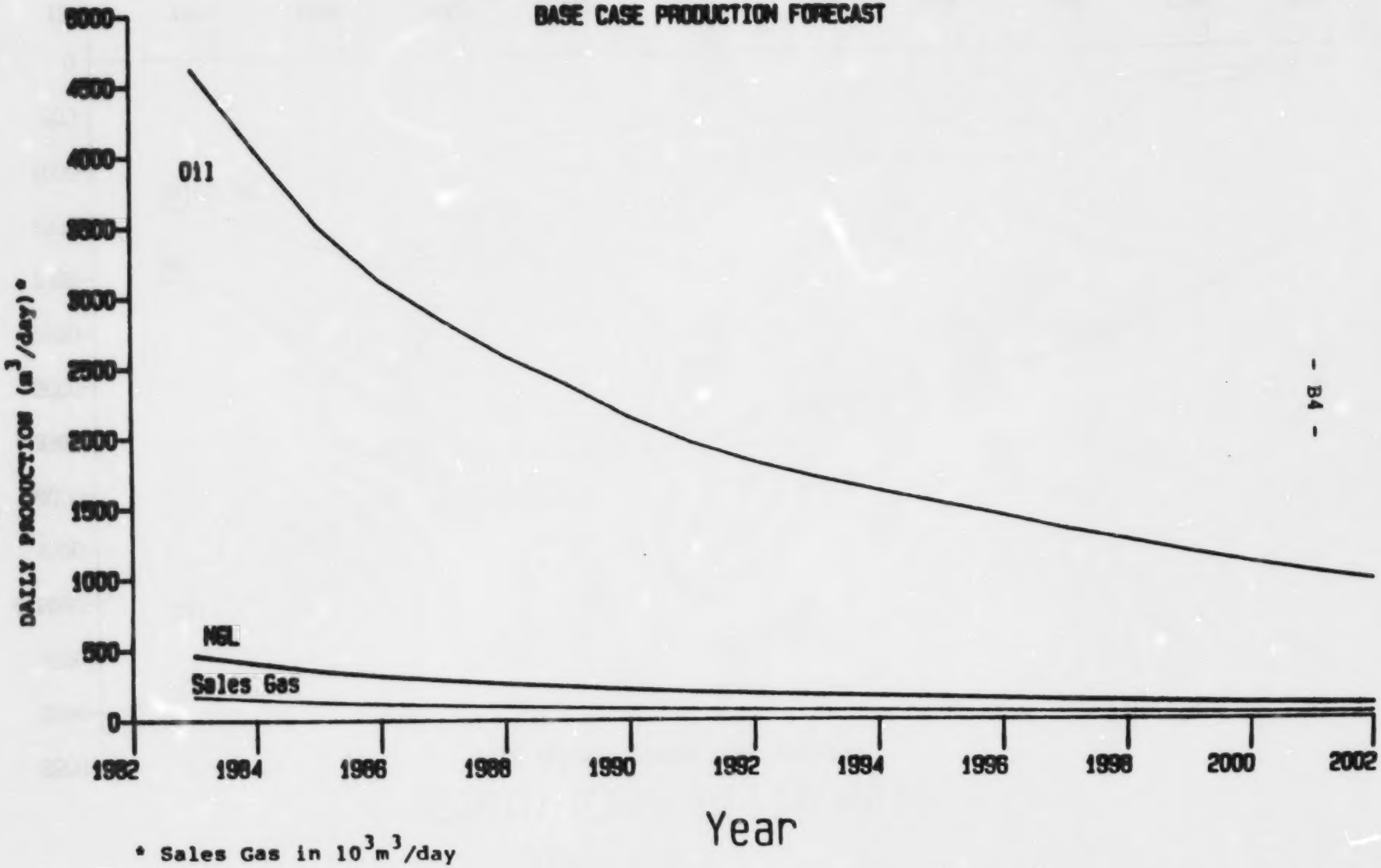


Figure B3

NIPISI GILWOOD UNIT 1

BASE CASE PRODUCTION FORECAST

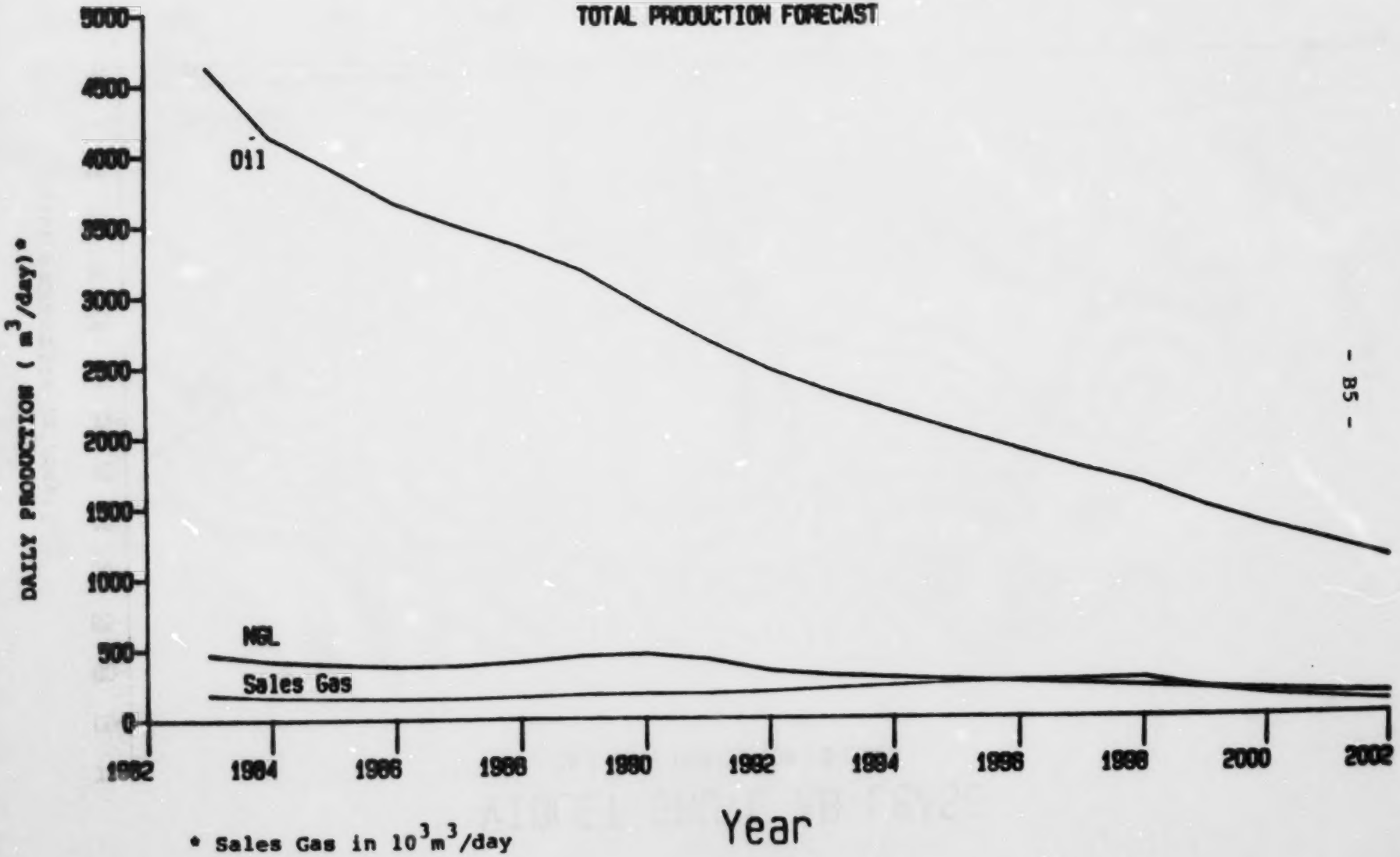


* Sales Gas in $10^3 m^3$/day

Figure B4

NIPISI GILWOOD UNIT 1

TOTAL PRODUCTION FORECAST



* Sales Gas in $10^3 m^3$/day

Figure B5

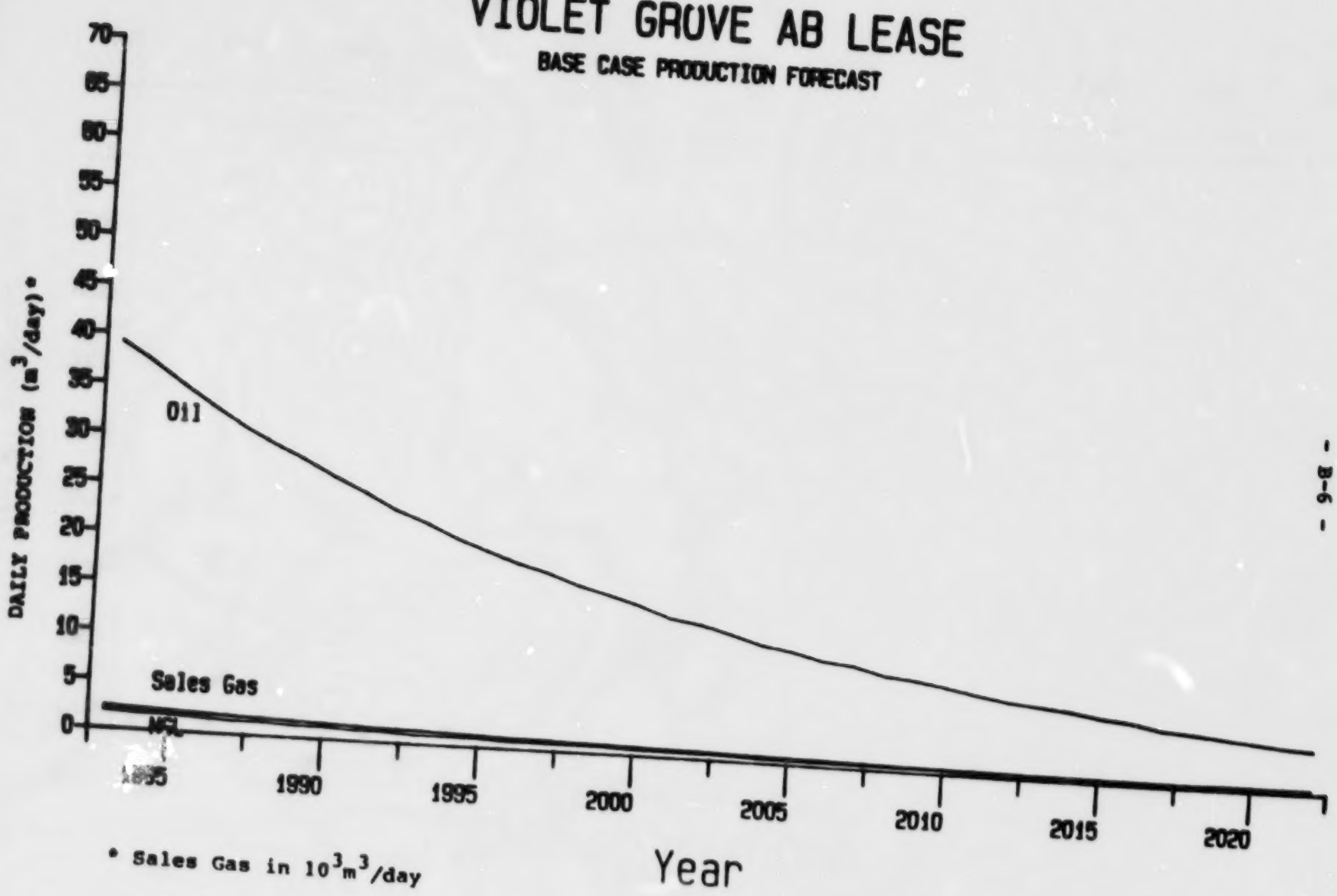
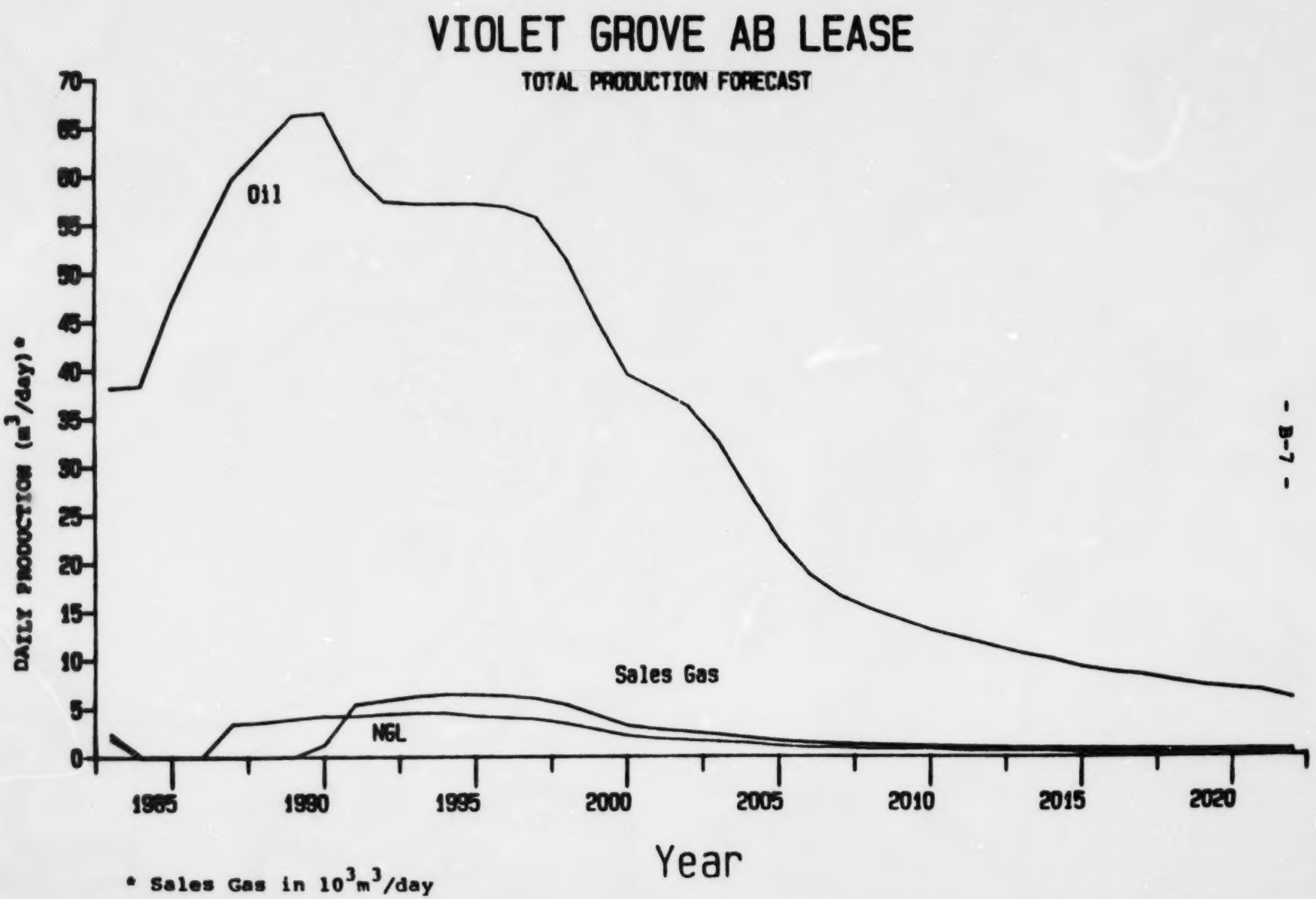

VIOLET GROVE AB LEASE
BASE CASE PRODUCTION FORECAST
DAILY PRODUCTION (m^3/day)*
70
65
60
55
50
45
40
35
30
25
20
15
10
5
0
Oil
Sales Gas
NGL
1990
1995
2000
2005
2010
2015
2020
Year
* Sales Gas in 10^3m^3/day

Figure B6


VIOLET GROVE AB LEASE
TOTAL PRODUCTION FORECAST
DAILY PRODUCTION (m^3/day)*
70
65
60
55
50
45
40
35
30
25
20
15
10
5
0
Oil
Sales Gas
NGL
1985
1990
1995
2000
2005
2010
2015
2020
Year
* Sales Gas in $10^3 m^3$/day

APPENDIX C

CASH FLOW RESULTS

Table C1

South Swan Hills
Net Present Value in Millions 1983 Dollars

A - Unrisked Base Case - Constant Real Price

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties
5%	3371.23	362.64	2671.15	257.12	700.08	105.52
7%	2956.87	317.16	2407.42	234.42	549.45	82.74
10%	2474.04	264.17	2090.21	206.43	393.83	57.74
15%	1916.38	203.01	1705.46	171.33	210.92	31.68

B - Increasing Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties
5%	4935.51	646.29	3706.38	459.43	1229.13	186.86
7%	5215.27	544.03	3249.75	397.23	965.52	146.80
10%	3400.63	429.81	2721.62	326.46	679.01	103.35
15%	2501.49	306.23	2116.66	247.42	384.83	58.81

Table C1 (cont'd)

C - Decreasing Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties
5%	2414.13	191.87	2016.18	133.08	397.95	58.79
7%	2170.99	177.73	1862.60	132.41	308.39	45.32
10%	1877.65	159.20	1668.59	128.79	209.06	30.41
15%	1521.35	134.32	1417.11	119.60	104.24	14.72

D - Oil Prices Deregulated[1]

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties
5%	3922.73	541.94	3232.21	488.98	690.52	52.96
7%	3443.51	476.61	2908.77	440.49	534.74	36.12
10%	2885.20	400.44	2520.91	382.14	364.29	18.30
15%	2240.42	312.32	2052.43	311.40	187.99	0.92

Table C1 (cont'd)

E - Oil Prices Deregulated (Old Royalty)[2]

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties
5%	3922.73	304.37	3232.21	293.25	690.52	11.12
7%	3443.51	269.60	2908.77	265.62	534.74	3.98
10%	2885.20	228.77	2520.91	232.01	364.29	-3.24
15%	2240.42	180.93	2052.43	190.65	187.99	-9.67

F - Incremental Recovery Increase

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties
5%	3528.74	418.60	2671.15	257.12	857.59	161.48
7%	3087.57	364.70	2407.42	234.42	680.15	130.28
10%	2574.71	302.10	2090.21	206.43	484.50	95.67
15%	1984.56	230.26	1705.46	171.33	279.10	58.93

Table C1 (cont'd)

G - Incremental Recovery Decreases

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties	w/o Taxes and Royalties	w/ Taxes and Royalties
5%	3213.61	328.85	2671.15	257.12	542.46	71.73
7%	2825.59	288.68	2407.42	234.42	418.17	54.26
10%	2372.32	241.69	2090.21	206.43	282.11	35.26
15%	1846.74	187.15	1705.46	171.33	141.28	15.82

Table C2

Nipisi Gilwood Unit 1
Net Present Values in millions of 1983 dollars

Unrisked Base Case -

A - Constant Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	2429.91	292.70	2071.54	235.02	358.37	57.68
7%	2150.63	258.04	1854.93	209.65	295.70	48.39
10%	1822.19	217.38	1597.95	179.70	224.24	37.68
15%	1437.26	169.90	1292.18	144.34	145.08	25.56

B - Increasing Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	3416.04	443.92	2820.64	352.71	595.40	91.21
7%	2951.86	379.74	2463.30	304.19	488.56	75.55
10%	2421.13	307.11	2052.82	249.25	368.31	57.86
15%	1824.95	226.76	1587.37	188.32	237.58	38.44

Table C2 (cont'd)

C - Decreasing Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	1809.1	199.97	1599.95	163.18	209.15	36.79
7%	1635.5	181.80	1463.25	150.64	172.25	31.16
10%	1425.2	159.38	1295.45	134.84	129.75	24.54
15%	1168.0	131.30	1085.86	114.47	82.14	16.33

D - Oil Prices Deregulated

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	3109.80	566.39	2694.76	496.48	415.04	20.36
7%	2754.58	500.84	2411.20	442.82	343.38	58.02
10%	2336.62	423.37	2075.17	379.51	261.45	43.86
15%	1846.37	332.79	1675.97	304.77	170.40	28.02

Table C2 (cont'd)

E - Oil Prices Deregulated (Old Royalty)

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	3109.80	298.89	2694.76	320.53	415.04	-21.64
7%	2759.58	261.61	2411.20	285.05	343.38	-23.44
10%	2336.62	218.44	2075.17	243.35	261.45	-24.91
15%	1846.37	169.00	1675.97	194.41	170.40	-25.41

F - Increase in Incremental Recovery

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	2501.00	302.38	2071.54	235.02	429.46	67.36
7%	2212.36	266.37	1854.93	209.65	357.45	56.72
10%	1870.86	224.14	1597.95	179.70	272.91	44.44
15%	1472.12	174.85	1292.18	144.34	179.94	30.51

Table C2 (cont'd)

G - Decrease in Incremental Recovery

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	2359.26	283.23	2071.54	235.02	287.72	48.21
7%	2090.25	249.89	1854.93	209.65	235.32	40.24
10%	1773.77	210.77	1597.95	179.70	175.82	31.07
15%	1402.56	165.06	1292.18	144.34	110.38	20.72

Table C3

Violet Grove AB Lease
Net Present Values in millions of 1983 dollars

A - Unrisked Base Case - Constant Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	41.83	10.25	21.78	7.04	20.05	3.21
7%	33.23	7.85	18.92	6.05	14.31	1.80
10%	24.13	5.39	15.75	4.97	8.38	0.42
15%	14.97	3.00	12.25	3.79	2.72	-0.79

B - Increasing Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	85.90	24.93	39.55	14.57	46.35	10.36
7%	65.30	18.17	31.52	11.30	33.78	6.87
10%	45.11	11.85	23.77	8.23	21.34	3.62
15%	26.53	6.37	16.60	5.50	9.93	0.87

Table C3 (cont'd)

C - Decreasing Real Prices

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	20.63	3.81	13.71	3.77	6.92	0.04
7%	16.85	3.00	12.74	3.59	4.11	-0.59
10%	12.57	2.07	11.40	3.27	1.17	-1.20
15%	7.93	1.05	9.56	2.77	-1.63	-1.72

D - Oil Prices Deregulated

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	48.94	13.32	29.57	10.72	19.37	2.60
7%	39.20	10.40	25.56	9.17	13.64	1.23
10%	28.90	7.39	21.15	7.49	7.75	-0.10
15%	18.47	4.44	16.35	5.70	2.12	-1.26

Table C3 (cont'd)

E - Oil Prices Deregulated (Old Royalty)

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	48.94	11.14	29.57	9.93	19.37	1.21
7%	39.20	8.63	25.56	8.47	13.64	0.16
10%	28.90	6.07	21.15	6.89	7.75	-0.82
15%	18.47	3.59	16.35	5.21	2.12	-1.62

F - Increase in Incremental Recovery

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	47.31	11.43	21.78	7.04	25.53	4.39
7%	37.69	8.81	18.92	6.05	18.77	2.76
10%	27.52	6.12	15.75	4.97	11.77	2.76
15%	17.24	3.50	12.25	3.79	4.99	-0.29

Table C3 (cont'd)

G - Decrease in Incremental Recovery

Real Discount Rate	Total Project		Base Case		Incremental Recovery	
	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties	w/o taxes and royalties	w/taxes and royalties
5%	36.15	9.01	21.78	7.04	14.37	1.97
7%	28.61	6.86	18.92	6.05	9.69	0.91
10%	20.64	4.64	15.75	4.97	4.89	-0.33
15%	12.64	2.50	12.25	3.79	0.39	-1.29

Table C4

South Swan Hills
Total Project NPV Revenue Shares
in Millions of 1983 Dollars
(% of Total NPV)

A - Total Project
Unrisked Base Case - Constant Real Price

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3371.23	1695.59 (50.3%)	1312.99 (38.95%)	362.64 (10.75%)
7%	2956.87	1488.14 (50.33%)	1151.56 (38.95%)	317.16 (10.72%)
10%	2474.04	1246.38 (50.38%)	963.49 (38.94%)	264.17 (10.68%)
15%	1916.38	967.05 (50.46%)	746.32 (38.94%)	203.01 (10.6%)

B - Total Project
Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	4935.51	2366.16 (47.94%)	1923.06 (38.97%)	646.29 (13.09%)
7%	4215.27	2028.90 (48.13%)	1642.34 (38.96%)	544.03 (12.91%)
10%	3400.63	1645.95 (48.40%)	1324.86 (38.96%)	429.81 (12.64%)
15%	2501.49	1220.75 (48.80%)	974.51 (38.96%)	306.23 (12.24%)

Table C4 (cont'd)

C - Total Project
Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2414.13	1282.54 (53.13%)	939.73 (38.92%)	191.87 (7.95%)
7%	2170.99	1148.19 (52.89%)	845.06 (38.92%)	177.73 (8.19%)
10%	1877.65	987.55 (52.59%)	730.90 (38.93%)	159.20 (8.48%)
15%	1512.35	794.77 (52.24%)	592.25 (38.93%)	134.32 (8.83%)

D - Total Project
Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3922.73	1852.71 (47.23%)	1528.08 (38.95%)	541.94 (13.82%)
7%	3443.51	1625.54 (47.21%)	1341.36 (38.95%)	476.61 (13.84%)
10%	2885.20	1360.91 (47.17%)	1123.84 (38.95%)	400.44 (13.88%)
15%	2240.42	1055.40 (47.11%)	872.69 (38.95%)	312.32 (13.94%)

Table C4 (cont'd)

E - Total Project
Increase in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3528.74	1751.93 (49.65%)	1358.21 (38.49%)	418.60 (11.86%)
7%	3087.57	1534.33 (49.69%)	1188.54 (38.49%)	364.70 (11.82%)
10%	2574.71	1281.29 (49.76%)	991.31 (38.50%)	302.10 (11.74%)
15%	1984.56	989.91 (49.88%)	764.38 (38.52%)	230.26 (11.6%)

F - Total Project
Decrease in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3213.61	1633.25 (50.82%)	1251.52 (38.94%)	328.85 (10.24%)
7%	2825.59	1436.55 (50.84%)	1100.37 (38.94%)	288.68 (10.22%)
10%	2372.32	1206.81 (50.87%)	923.82 (38.94%)	241.69 (10.19%)
15%	1846.74	940.43 (50.92%)	719.16 (38.94%)	187.15 (10.14%)

Table C5

South Swan Hills
Base Case Project NPV Revenue Shares
in Millions of 1983 Dollars
(% of Total NPV)

A - Unrisked Base Case
Constant Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2671.15	1372.27 (51.37%)	1041.75 (39.00%)	257.12 (9.63%)
7%	2407.42	1234.11 (51.26%)	938.89 (39.00%)	234.42 (9.74%)
10%	2090.21	1068.61 (51.12%)	815.19 (39.00%)	206.43 (9.88%)
15%	1705.46	869.00 (50.95%)	665.12 (39.00%)	171.33 (10.05%)

B - Base Case Project
Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3706.38	1801.47 (48.60%)	1445.49 (39.00%)	459.43 (12.40%)
7%	3249.75	1585.12 (48.78%)	1267.40 (39.00%)	397.23 (12.22%)
10%	2721.62	1333.73 (49.00%)	1061.43 (39.00%)	326.46 (12.00%)
15%	2116.66	1043.74 (49.31%)	825.50 (39.00%)	247.42 (11.69%)

Table C5 (cont'd)

C - Base Case Project
Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2016.18	1096.79 (54.40%)	786.31 (39.00%)	133.08 (6.6%)
7%	1862.60	1003.77 (53.89%)	726.41 (39.00%)	132.41 (7.11%)
10%	1668.59	889.05 (53.28%)	650.75 (39.00%)	128.79 (7.72%)
15%	1417.11	744.84 (52.56%)	552.67 (39.00%)	119.60 (8.44%)

D - Base Case Project
Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3232.21	1482.67 (45.87%)	1260.57 (39.00%)	488.98 (15.13%)
7%	2908.77	1333.86 (45.86%)	1134.42 (39.00%)	440.49 (15.14%)
10%	2520.91	1155.61 (45.84%)	983.16 (39.00%)	382.14 (15.16%)
15%	2052.43	940.58 (45.83%)	800.44 (39.00%)	311.40 (15.17%)

* E - Increase in Incremental Recovery - same as the unrisked base case.

F - Decrease in Incremental Recovery - same as the unrisked base case.

Table C6

Nipisi Gilwood Unit 1
Total Project NPV Revenue Shares
in Millions of 1983 Dollars
(% of Total NPV)

A - Total Project
Unrisked Base Case - Constant Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2429.91	1191.47 (49.03%)	945.74 (38.92%)	292.70 (12.05%)
7%	2150.63	1055.61 (49.08%)	836.96 (38.92%)	258.04 (12.00%)
10%	1822.19	895.74 (49.16%)	709.06 (38.91%)	217.38 (11.93%)
15%	1437.26	708.15 (49.27%)	559.20 (38.91%)	169.90 (11.82%)

B - Total Project
Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3416.04	1641.78 (48.06%)	1330.33 (38.94%)	443.92 (13.00%)
7%	2951.86	1422.67 (48.20%)	1149.45 (38.94%)	379.74 (12.86%)
10%	2421.13	1171.37 (48.38%)	942.66 (38.93%)	307.11 (12.68%)
15%	1824.95	887.79 (48.65%)	710.39 (38.93%)	226.76 (12.42%)

Table C6 (cont'd)

Net Revenue Shares

C - Total Project
Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	1809.10	905.49 (50.05%)	703.63 (38.89%)	199.97 (11.06%)
7%	1635.50	817.63 (49.99%)	636.07 (38.89%)	181.80 (11.12%)
10%	1425.20	711.61 (49.93%)	554.25 (38.89%)	159.38 (11.18%)
15%	1168.00	582.51 (49.87%)	454.19 (38.89%)	131.30 (11.24%)

D - Total Project
Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	3109.80	1332.05 (42.83%)	1210.91 (38.94%)	566.84 (18.23%)
7%	2754.58	1181.23 (42.88%)	1072.51 (18.64%)	500.84 (18.18%)
10%	2336.62	1003.56 (42.95%)	909.70 (38.93%)	423.37 (18.12%)
15%	1846.37	794.82 (43.05%)	718.75 (38.93%)	332.79 (18.02%)

Table C6 (cont'd)

Net Revenue Shares

E - Total Project
Increase in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2501.00	1225.15 (48.99%)	973.47 (38.92%)	302.38 (12.09%)
7%	2211.36	1084.33 (49.03%)	860.65 (38.92%)	266.37 (12.05%)
10%	1870.86	918.68 (49.11%)	728.04 (38.91%)	224.14 (11.98%)
15%	1472.12	724.47 (49.21%)	572.79 (38.91%)	174.85 (11.88%)

F - Total Project
Decrease in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2359.26	1157.84 (49.08%)	918.19 (38.92%)	283.23 (12.00%)
7%	2090.25	1026.94 (49.13%)	813.42 (38.91%)	249.89 (11.96%)
10%	1773.77	872.82 (49.21%)	690.18 (38.91%)	210.77 (11.88%)
15%	1402.56	691.83 (49.33%)	545.67 (38.91%)	165.06 (11.77%)

Table C7

Nipisi Gilwood Unit 1
Base Case Project NPV Revenue Shares
in Millions of 1983 Dollars
(% of Total NPV)

A - Base Case Project
Unrisked Base Case - Constant Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2071.54	1028.61 (49.65%)	807.90 (39.00%)	235.02 (11.35%)
7%	1854.93	921.85 (49.70%)	723.42 (39.00%)	209.65 (11.30%)
10%	1597.95	795.05 (49.75%)	623.20 (39.00%)	179.70 (11.25%)
15%	1292.18	643.90 (49.83%)	503.95 (39.00%)	144.34 (11.17%)

B - Base Case Project
Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2820.64	1367.88 (48.49%)	1100.05 (39.00%)	352.71 (12.51%)
7%	2463.30	1198.43 (48.65%)	960.69 (39.00%)	304.19 (12.35%)
10%	2052.82	1002.97 (48.86%)	800.60 (39.00%)	249.25 (12.14%)
15%	1587.37	779.98 (49.14%)	619.07 (39.00%)	188.32 (11.86%)

Table C7 (cont'd)

Net Revenue Shares

C - Base Case Project
Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	1599.95	812.78 (50.80%)	623.98 (39.00%)	163.18 (10.20%)
7%	1463.25	741.94 (50.70%)	570.67 (39.00%)	150.64 (10.30%)
10%	1295.45	655.38 (50.60%)	505.22 (39.00%)	134.84 (10.40%)
15%	1085.86	547.90 (50.46%)	423.48 (39.00%)	114.47 (10.54%)

D - Base Case Project
Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	2694.76	1147.32 (42.58%)	1050.95 (39.00%)	496.48 (18.52%)
7%	2411.20	1028.02 (42.64%)	940.36 (39.00%)	442.82 (18.36%)
10%	2075.17	886.34 (42.71%)	809.32 (39.00%)	379.51 (18.29%)
15%	1675.97	717.56 (42.18%)	653.63 (39.00%)	304.77 (18.18%)

* E - Increase in Incremental Recovery - same as the unrisked base case.

F - Decrease in Incremental Recovery - same as the unrisked base case.

Table C8

Violet Grove AB Lease
Total Project NPV Revenue Shares
in Millions of 1983 Dollars
(% of Total NPV)

A - Total Project
Unrisked Base Case - Constant Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	41.83	15.50 (37.04%)	16.09 (38.46%)	10.25 (24.50%)
7%	33.23	12.61 (37.96%)	12.76 (38.41%)	7.85 (23.63%)
10%	24.13	9.48 (39.29%)	9.26 (38.38%)	5.39 (22.33%)
15%	14.97	6.21 (41.48%)	5.75 (38.41%)	3.00 (20.11%)

B - Total Project
Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	85.90	27.74 (32.30%)	33.23 (38.68%)	24.93 (29.02%)
7%	65.30	21.88 (33.52%)	25.24 (38.65%)	18.17 (27.83%)
10%	45.11	15.85 (35.13%)	17.42 (38.61%)	11.85 (26.26%)
15%	26.53	9.93 (37.43%)	10.23 (38.56%)	6.37 (24.01%)

Table C8 (cont'd)

Net Present Value Revenue Shares

C - Total Project
Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	20.63	8.99 (43.58%)	7.83 (37.95%)	3.81 (18.47%)
7%	16.85	7.45 (44.23%)	6.38 (37.89%)	3.00 (17.86%)
10%	12.57	5.73 (45.61%)	4.76 (37.89%)	2.07 (16.50%)
15%	7.93	3.87 (48.75%)	3.02 (38.07%)	1.05 (13.18%)

D - Total Project
Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	48.94	16.78 (34.29%)	18.84 (38.50%)	13.32 (27.21%)
7%	39.20	13.72 (35.00%)	15.08 (38.47%)	10.40 (26.53%)
10%	28.90	10.40 (35.99%)	11.11 (38.44%)	7.39 (25.57%)
15%	18.47	6.93 (37.51%)	7.11 (38.49%)	4.44 (24.00%)

Table C8 (cont'd)

Net Present Value Revenue Shares

E - Total Project
Increase in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	47.31	17.66 (37.33%)	18.21 (38.50%)	11.43 (24.17%)
7%	37.69	14.38 (38.15%)	14.50 (38.47%)	8.81 (23.38%)
10%	27.52	10.82 (39.32%)	10.58 (38.44%)	6.12 (22.24%)
15%	17.24	7.11 (41.21%)	6.64 (38.50%)	3.50 (20.25%)

F - Total Project
Decrease in Incremental Recovery

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	36.15	13.27 (36.70%)	13.88 (38.40%)	9.01 (24.90%)
7%	28.61	10.78 (37.68%)	10.97 (38.34%)	6.86 (23.98%)
10%	20.64	8.09 (39.19%)	7.91 (38.33%)	4.64 (22.48%)
15%	12.64	5.29 (41.85%)	4.85 (38.37%)	2.50 (19.78%)

Table C9

Violet Grove AB Lease
Base Case Project NPV Revenue Shares
in Millions of 1983 Dollars
(% of Total NPV)

A - Base Case Project
Unrisked Base Case - Constant Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	21.78	6.24 (28.66%)	8.49 (39.00%)	7.04 (32.34%)
7%	18.92	5.49 (29.02%)	7.38 (39.00%)	6.05 (31.98%)
10%	15.75	4.64 (29.47%)	6.14 (39.00%)	4.97 (31.57%)
15%	12.25	3.69 (30.10%)	4.78 (39.00%)	3.79 (30.90%)

B - Base Case Project
Increasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	39.55	9.55 (24.15%)	15.43 (39.01%)	14.57 (36.84%)
7%	31.52	7.92 (25.13%)	12.29 (39.00%)	11.30 (35.87%)
10%	23.77	6.26 (26.36%)	9.27 (39.00%)	8.23 (34.64%)
15%	16.60	4.63 (27.90%)	6.47 (38.96%)	5.50 (33.14%)

Table C9 (cont'd)

Net Present Value Revenue Shares

C - Base Case Project
Decreasing Real Prices

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	13.71	4.59 (33.48%)	5.35 (39.02%)	3.77 (32.50%)
7%	12.74	4.19 (32.87%)	4.97 (39.00%)	3.59 (28.13%)
10%	11.40	3.68 (32.28%)	4.45 (39.04%)	3.27 (28.68%)
15%	9.56	3.06 (32.01%)	3.73 (39.02%)	2.77 (28.97%)

D - Base Case Project
Oil Prices Deregulated

Real Discount Rate	Total Net Revenue	Provincial Government	Federal Government	Company
5%	29.57	7.32 (24.76%)	11.54 (39.04%)	10.72 (36.23%)
7%	25.56	6.42 (25.12%)	9.97 (39.01%)	9.17 (35.87%)
10%	21.15	5.41 (25.58%)	8.25 (39.01%)	7.49 (35.41%)
15%	16.35	4.27 (26.12%)	6.37 (38.98%)	5.70 (34.90%)

E - Increase in Incremental Recovery - same as the unrisked base case

F - Decrease in Incremental Recovery - same as the unrisked base case

Table C10

Real Supply Costs - South Swan Hills
10 per cent real discount rate in 1983 dollars
$/m^3 ($/bbl)

Real Discount Rate	Total Project Social Supply Cost	Total Project Private Supply Cost	Base Case Project Social Supply Cost	Base Case Project Private Supply Cost	Incremental Recovery Social Supply Cost	Incremental Recovery Private Supply Cost
Constant Real Prices	40.06 (6.37)	121.73 (19.34)	36.17 (5.75)	123.47 (19.62)	57.26 (9.10)	114.04 (18.12)
Increasing Real Prices	42.55 (6.76)	159.19 (25.30)	37.94 (6.03)	154.41 (24.54)	62.93 (10.00)	180.33 (28.66)
Decreasing Real Prices	37.63 (5.98)	128.35 (15.46)	34.47 (5.48)	102.48 (16.28)	51.60 (8.20)	74.28 (11.80)
NORP Pricing Scenario	41.31 (6.56)	136.01 (21.61)	37.45 (5.95)	140.10 (22.26)	58.38 (9.28)	117.92 (18.74)
Increase in Incremental Recovery	39.90 (6.34)	126.56 (20.11)	36.17 (5.75)	123.47 (19.62)	55.36 (8.80)	123.93 (19.69)
Decrease in Incremental Recovery	40.23 (6.39)	119.30 (18.96)	36.17 (5.75)	123.47 (19.62)	59.55 (9.46)	99.46 (15.80)

Table C11

Real Supply Costs - Nipisi Gilwood Unit 1
10 per cent real discount rate in 1983 dollars
$/m^3 ($/bbl)

Sensitivity Scenario	Total Project Social Supply Cost	Total Project Private Supply Cost	Base Case Project Social Supply Cost	Base Case Project Private Supply Cost	Incremental Recovery Social Supply Cost	Incremental Recovery Private Supply Cost
Unrisked Base Case - Constant Real Prices	22.18 (3.52)	152.38 (24.21)	11.92 (1.89)	152.87 (24.29)	71.79 (11.41)	150.01 (23.84)
Increasing Real Prices	22.61 (3.59)	197.42 (31.37)	12.10 (1.92)	193.99 (30.83)	73.43 (11.67)	214.01 (34.01)
Decreasing Real Prices	21.73 (19.44)	122.33 (19.44)	11.74 (1.87)	125.33 (19.92)	70.04 (11.13)	107.82 (17.13)
Oil Prices Deregulated	22.56 (3.58)	184.02 (29.24)	11.92 (1.89)	180.44 (28.67)	74.01 (11.76)	201.33 (31.99)
Increase in Incremental Recovery	21.82 (3.47)	153.27 (24.36)	11.92 (1.89)	152.87 (24.29)	65.01 (10.33)	155.01 (24.63)
Decrease in Incremental Recovery	22.55 (3.58)	151.45 (24.07)	11.92 (1.89)	152.87 (24.29)	80.24 (12.75)	143.74 (22.84)

Table C12

Real Supply Costs - Violet Grove AB Lease
10 per cent real discount rate in 1983 dollars
$/m^3 ($/bbl)

Real Discount Rate	Total Project Social Supply Cost	Total Project Private Supply Cost	Base Case Project Social Supply Cost	Base Case Project Private Supply Cost	Incremental Recovery Social Supply Cost	Incremental Recovery Private Supply Cost
Base Case Scenario - Constant Real Prices	84.00 (13.35)	180.45 (28.67)	31.04 (4.93)	131.02 (20.82)	148.71 (23.63)	240.85 (38.27)
Increasing Real Prices	85.22 (13.54)	258.90 (41.14)	31.53 (5.01)	177.73 (28.18)	150.82 (23.97)	358.02 (56.89)
Decreasing Real Prices	82.55 (6.29)	135.66 (21.56)	30.55 (4.85)	104.71 (16.64)	146.09 (23.21)	173.48 (27.57)
Oil Prices Deregulated	84.37 (13.41)	195.58 (31.08)	31.40 (4.99)	159.46 (25.34)	149.09 (23.69)	239.72 (38.09)
Increase in Incremental Recovery	79.53 (12.64)	183.56 (29.17)	31.04 (4.93)	131.02 (20.82)	131.58 (20.91)	239.96 (38.13)
Decrease in Incremental Recovery	88.99 (14.14)	176.50 (28.05)	31.04 (4.93)	131.02 (20.82)	171.30 (27.22)	241.10 (38.31)

Notes

1 In the Oil Prices Deregulated Case all oil recieves NORP and pays NORP royalties.

2 In the Oil Prices Deregulated (Old Royalty) Case all oil qualifies for NORP but is assumed to pay Old Oil Royalties.

3 In all cases the "Total Project" results are the economics of the total project area, which includes the miscible flood.

4 In all cases the "Base Case" results are the economics of the "base case project" without the miscible flood.

5 It should be noted that an increase (decrease) in incremental recovery only affects the total project economics. Consequently when incremental recovery increases (decreases) the "base case project" economics remain unchanged from the unrisked base case.

APPENDIX D

EOR INCENTIVES TAX CALCULATIONS AND ROYALTIES

Section 4.2 - Petroleum Royalty Relief for EOR Schemes

On January 1, 1977 Section 4.2 was introduced by the Alberta Governmnent in an effort to encourage the development of high cost, risky EOR projects. This incentive was in the form of reduced royalties payable. In an effort to further encourage the development of EOR projects the provincial government made the following three ammendments to Section 4.2 on October 14, 1982:[1]

1 The overhead cost allowance was increased from 10 to 25 per cent of operating costs.

2 The capital depreciation allowance was increased from 10 per cent on a straight line basis to 30 per cent on a declining balance basis.

3 Operators of EOR projects no longer have to satisfy the ERCB that the project would not proceed without these incentives.

These ammendments were found to have a significant effect on the economics of various potential EOR projects.

This section proceeds with an explanation of guidelines for allowable costs as outlined in Section 4.2. This will be followed by a working example which calculates the royalties payable with and without EOR deductions for an EOR project.

Guidelines for Allowable Costs[2]

Each project approved by the Minister to receive credit, for deduction of incremental costs in accordance with Section 4.2 of the Petroleum Royalty Regulations, shall have those costs credited in acccordance with the following specifications and conditions.

Incremental costs will be the most significant incremental costs pertaining to the establishment and operation of an enhanced recovery scheme, plus an allowance of 25 per cent for undefined costs and overhead.

Definitions

For the purposes of defining the cumulative allowable costs associated with the injection of gas, liquids or fluids, the following terms are prescribed:

Maximum Volume - The cost in the case of purchased gas, liquids or fluids or the opportunity selling price in the case of proprietory gas or liquids or fluids injected, up to a maximum volume which is established for each scheme and is determined as the injection volume that equals the ultimate displaceable pore volume that will be contacted by injected gases, liquids or fluids at the time of attainment of the projected total recovery. Where a

scheme incorporates water injection for mobility control the maximum volume will be reduced by the water-alternating-gas (WAG) ratio specified in the ERCB Approval assigned under Section 26 of the Oil and Gas Conservation Act.

Maximum Solvent Bank Volume - Within the maximum volume specified above, the Department will identify, where appropriate, the maximum solvent bank volume eligible for opportunity cost deduction with the remaining volume identified as push or chase gas. The maximum solvent bank volume will correspond to the volume specified in the ERCB Approval assigned under Section 26 of the Oil and Gas Conservation Act.

Maximum Push (Chase) Gas Volume - The difference between the maximum volume and the maximum solvent bank volume.

Opportunity Selling Price - The price calculated using fair market value, less imputed Crown royalty, plus a processing allowance not to exceed the gas cost allowance established for the facility at which the gas and/or liquids are processed.

Operating

i) The cumulative cost creditable in the case of the maximum solvent bank volume is the maximum solvent bank volume times a present worth factor of 90 per cent of the cost or opportunity selling price of the said fluids,

ii) The cumulative cost creditable in the case of the maximum push (chase) gas volume is the maximum push (chase) gas volume times a present worth factor of 90 per cent of the cost or opportunity selling price of the said fluids,

A breakthrough volume discount factor of 80 per cent is applied annually to the injected push gas volumes until the cumulative injection is equal to the maximum push gas volume allowed,

iii) the cost of injected non-hydrocarbon fluids, such as nitrogen, carbon dioxide, sulphur dioxide, polymers and surfactants are credited in the same manner as hydrocarbon fluids,

iv) the cost of energy consumed to operate the scheme which is incremental to the base case scheme in the same project,

v) an allowance for transportation where appropriate,

vi) an allowance not to exceed the processing allowance for all gas, liquids or other fluids injected in excess of the maximum specified injection volumes.

Capital

Amortization of Incremental Capital Costs at a rate of 30 per cent on the reducing balance, commencing on the date of first operation of the facilities, taken only on the following:

i) wells and well conversions in addition to these which in the view of the ERCB would have been needed for a suitable waterflood scheme in a similar reservoir,

ii) pumps, compressors, mixing facilities, power generators and pipelines in addition to those which in the view of the Department, in consultation with the ERCB, would have been needed for a suitable waterflood scheme,

iii) pollution controls,

iv) fluid clean up or separation facilities for such substances as emulsions or noxious gases,

v) storage facilities for fluids to be injected, including chemical additives, in addition to those which in the view of the Department, in consultation with the ERCB, would have been needed for a suitable waterflood scheme,

vi) generating facilites for steam, nitrogen, carbon dioxide or similar substances and their auxiliaries,

vii) interest on construction at the prevailing prime rate plus 1 per cent applied annually to the average cumulative investment in capital costs incurred prior to the date of first operation.

Cost Carry Forward:

If in any month the incremental costs, plus a carry forward of any excess of such costs for the previous month over the total revenue from the sale of crude oil for the previous month, exceed the total revenue from the sale of crude oil for the month, the excess shall be added to the incremental costs for the subsequent month.

Notes:

1 Incremental costs are to be reduced by any rebate or royalty relief granted under other sections of the Petroleum Royalty Regulations if the rebate or relief is applicable to the gas or hydrocarbon fluids injected during the corresponding period. If the rebate is applicable to hydrocarbon fluids injected prior to commencement of 4.2 relief, the rebate will be allowed against royalty payable until such time as the accumulated rebate credit is depleted.

2 The gas or hydrocarbon fluids injected retain their "new" gas status for royalty purposes as long as there was not a sale or consumption for a useful purpose from the pool from which they were produced.

Horizontal Flood

Hydrocarbon Solvent Bank, Chase Gas, WAG (Water-Alternating Gas) Injection

$$\text{Maximum volume} = \text{RiN (total)}\ Bo \times \frac{1}{1 + \text{WAG}}\ (Rm^3)$$

Where RiN (total) = RiN (primary) + RiN (waterflood) + Rin (miscible flood) within the area confines of the tertiary flood scheme

Solvent bank volume = E.R.C.B. approval (Rm^3)

Maximum chase gas volume = maximum volume minus solvent bank volume (Rm^3)

Annual Allowable injection = [[(cost of solvent) X .90 + (gas cost allowance for injection) (in excess of solvent bank volumes)] + [(cost of chase gas volume) X .90 X .80 + (gas cost allowance for injection) (in excess of push gas volumes)] X 1.25

Notes:

(i) In the preceding, while the volumes allowed on an annual basis are discounted by 20 per cent, the cumulative total or maximum push gas volumes must not exceed the volumes determined or prescribed at the time of approval.

(ii) A component of injection for purposes of repressuring will be recognized.

Example: Effect of Section 4.2 EOR Royalty Reduction

Assumptions:

1 Old Oil Price = $\$187/m^3$

2 NORP = $245/m^3$

3 Remaining Waterflood Reserves = $6x10^6m^3$

4 Estimated Incremental EOR Production = $4x10^6m^3$

5 Production Rate = $20m^3$/day

6 Old Oil Royalty Rate = 40 per cent

7 NORP Oil Rate = 30 per cent

8 Solvent Costs = $40,000

9 Chase Gas Costs = $25,000

10 Capital Costs = $200,000

11 Gas cost allowance for injection = 0

12 All materials are purchased.

The "a" factor is the fraction of production which earns NORP and pays NORP royalties

$$\text{"a" factor} = \frac{\text{Total Recovery Including EOR - Remaining Waterflood Recovery}}{\text{Total Recovery Including EOR}}$$

$$= \frac{10,000 - 6,000}{10,000}$$

$$= 0.4$$

Blended Oil Price = .4(245) + .6(187)

= $210.20/$m^3$

Gross Oil Revenue = $210.20/$m^3$ X 20m^3/day X 365

= $1.53 million

Blended Oil Royalty = .4(NORP Royalty) + .6(Old Oil Royalty Rate

= .4(30) + .6(40)

= 36 per cent

Royalties Payable without EOR Royalty Relief

= Gross Oil Revenue X Blended Oil Royalty Rate

= 1.53 million X .36

= $551,000

Royalties Payable with EOR Royalty Relief

Solvent Costs = $40,000

Chase Gas Costs = $25,000

Capital Costs = $200,000

Gas Cost Allowance = 0

All injection materials are purchased.

Annual Allowable Injection = [(Cost of Solvent X.9)
Material Costs

+ (Cost of chase gas X.9X.8)] X 1.25 1)

= [(40,000 X .9) + (25,000 X .9 X .8)] X 1.25

= 67,500

Capital Depreciation Allowance = Eligible Capital Costs X .3 2)

= 200,000 X .3

= 60,000

∴ total cost deduction = 1 + 2 = 127,500

Total Oil Revenue	1.53 million
Total Cost Deduction	.127 million
Revenue on which royalties to be paid	1.403 million

Royalty payable After EOR Deduction = Revenue on which royalties to be paid X blended oil royalty rate

= 1.403 X .36

= $505,000

Royalty Payable without EOR Deduction = $551,000

PGRT Relief[3]

In the April 1983 budget the federal government announced that all new EOR projects would be exempt from all PGRT payments until after payout occurs. In May 1983, the Federal government provided further PGRT relief for EOR projects by announcing that participants in EOR projects could "deduct eligible capital expenditures from the projected revenue of the project." This is thought to be better than no PGRT until after payout because now participants in EOR projects would be exempt from PGRT payments until after all eligible capital investments have been recovered.

Working Example: PGRT Relief for EOR Projects

Assumptions:

1 NORP = $\$245/m^3$

2 Old Oil Price = $\$187/m^3$

3 Total Resource Revenue = $1.5 million

4 Incremental Recovery Revenue = $500,000

5 Total Operating Costs = 150,000

6 EOR project operating costs = 100,000

7 Resource Royalties = 0

8 Eligible Capital Costs = 500,000

9 Small Producer Credit = 0

PGRT Calculation with the Capital Deduction Included

Project Capital Deduction

Project gross revenue	$ 500,000
less: project operating costs	100,000
: resource royalty	0
= project production revenue	$ 400,000
Claim the lesser of project net revenue and cumulative eligible capital costs	$ 400,000
Capital Cost Carry Forward	$ 100,000

PGRT Calculation

Total Gross Revenue	$1,500,000
less: total operating costs	150,000
resource royalty	0
= total production revenue	$1,350,000
less: allowed capital deduction	$ 400,000
	$ 950,000
resource allowance	237,000
= PGRT tax base	$ 713,000
PGRT @ 16 per cent	$ 114,000
less: small producer credit	0
= Net PGRT payment	$ 114,000

PGRT Calculation without the Capital Deduction

PGRT Calculation

Total Gross Revenue	$1,500,000
less: total operating costs	150,000
resource royalty	0
= total production revenue	$1,350,000
less: resource allowance	337,500
= PGRT tax base	$1,012,500
PGRT @ 16 per cent	$ 162,000
less: small producer credit	0
= Net PGRT Payment	$ 162,000

The PGRT payment with the capital deduction is $48,000 less than the PGRT payment without the capital deduction. This example illustrates that the Federal government's PGRT Relief for EOR projects could considerably improve the economics of an EOR project which has high capital costs spread out over the project's life.

Federal Tax Calculations

Assumptions:

1 Old Oil Price = $187.21/$m^3$

2 NORP = $246.1/$m^3$

3 Annual Production = 10000m^3

4 Freehold Portion = 33.6%

5 Freehold Royalty Rate = 12.5%

6 Capital Expenditures = $500,000 CDE
$100,000 Class 10

7 Operating Costs = $250,000

8 NORP Fraction = .75

9 No PGRT Relief

PGRT Calculation*

Gross Revenue:	$2,313,775	
less: Operating Costs	250,000	
= Net Production Revenue	$2,063,775	
less: Resource Allowance	515,944	
= PGRT Tax Base	$1,547,831	
PGRT @ 16%		247,653

Income Tax Calculation

Gross Revenue:	$2,313,775	
less: Operating Costs	250,000	
Freehold Royalties	289,222	
CCA on Class 10 @ 30%	30,000	
Net Resource Profits	$1,744,553	
less: Depletion	33,333	
Net Taxable Income	$1,711,220	
Federal Tax @ 36%	$ 616,039	
less: Investment Tax Credit	10,000	
Net Federal Income Tax	$ 606,039	
plus: PGRT	247,653	
Total Federal Taxes Payable		853,692

Alberta Royalties

Effective April 1, 1982 the Alberta government introduced amendments to the old oil/new oil royalty formula. Policy intention is to collect 21 2/3 per cent of the first $40.90 per cent cubic metre, i.e., base or select price, for a 'reference' well and a marginal rate on the par price in excess of the select price. Currently the marginal royalty rates are 35 per cent for NORP oil and 45 per cent for old oil and the 'reference" well is a well which produces 572.1 cubic metres per month.

Both old and new royalties are a function of both production and oil prices. The basic royalty formula for old and new oil in the Province of Alberta is as follows:

$S = (Production^2)/1271.28$ if monthly production is less than or equal to $190.7m^3$

$S = 28.6m^3 + .25\ (Production - 190.7m^3)$ if monthly production is greater than $190.7m^3$

S = basic royalty in cubic metres

In order to calculate royalties payable, the basic royalty is inserted into the royalty formula as follows:

R = S + ((A-B/A))

R; royalty payable in cubic metres

A; par price (currently $\$187.21/m^3$ for old oil and $\$246.10/m^3$ for NORP oil)

B; select price ($\$40.90/m^3$ for both old and NORP oil)

K; royalty factor which sets the royalty formula equal to the intent formula on the reference well (currently 0.615385 for NORP oil and 1.07701 for old oil)

Royalty rates for various production rates and oil prices are presented in Figures D1 and D2 respectively. It should be noted that the average royalty rate for old oil is greater than the average royalty rate for NORP oil for all production levels and oil prices. In spite of this royalties payable in dollars are greater for NORP oil at all levels of production and oil prices because NORP is greater than the old oil price.

Deregulation of Oil Prices and Royalties

Under existing legislation for EOR projects a portion of total production pays old oil royalties and the remainder pays NORP as calculated by the 'fixed ratio method'. As domestic oil prices move towards world market prices the NORP fraction, i.e., fraction of total production paying NORP royalties increases. Consequently, the blended royalty rate decreases. However, total royalties payable in dollars increase because of the higher price received by each cubic metre of oil. This is shown in Table D1 and Figure D3 for various NORP fractions for a 'reference' well. It should also be noted that the larger the NORP faction before deregulation the smaller the impact of deregulation on the economics of the project.

Table D1

NORP Fraction	Blended Royalty Rate (%)	Total Royalties* Payable ($1983)
0.0	39.90	42736.39
.1	39.188	43078.36
.2	38.476	43420.34
.3	37.764	43762.31
.4	37.052	44104.29
.5	36.340	44446.26
.6	35.628	44788.23
.7	34.916	45130.21
.8	34.204	45472.18
.9	33.492	45814.16
1.0	32.78	46156.13

Production = 572.1 m^3/month

NORP = \$246.1/m^3

Old Oil Price = \$187.21/m^3

* Does not include Section 4 or 4.2 royalty relief.

Figure D1

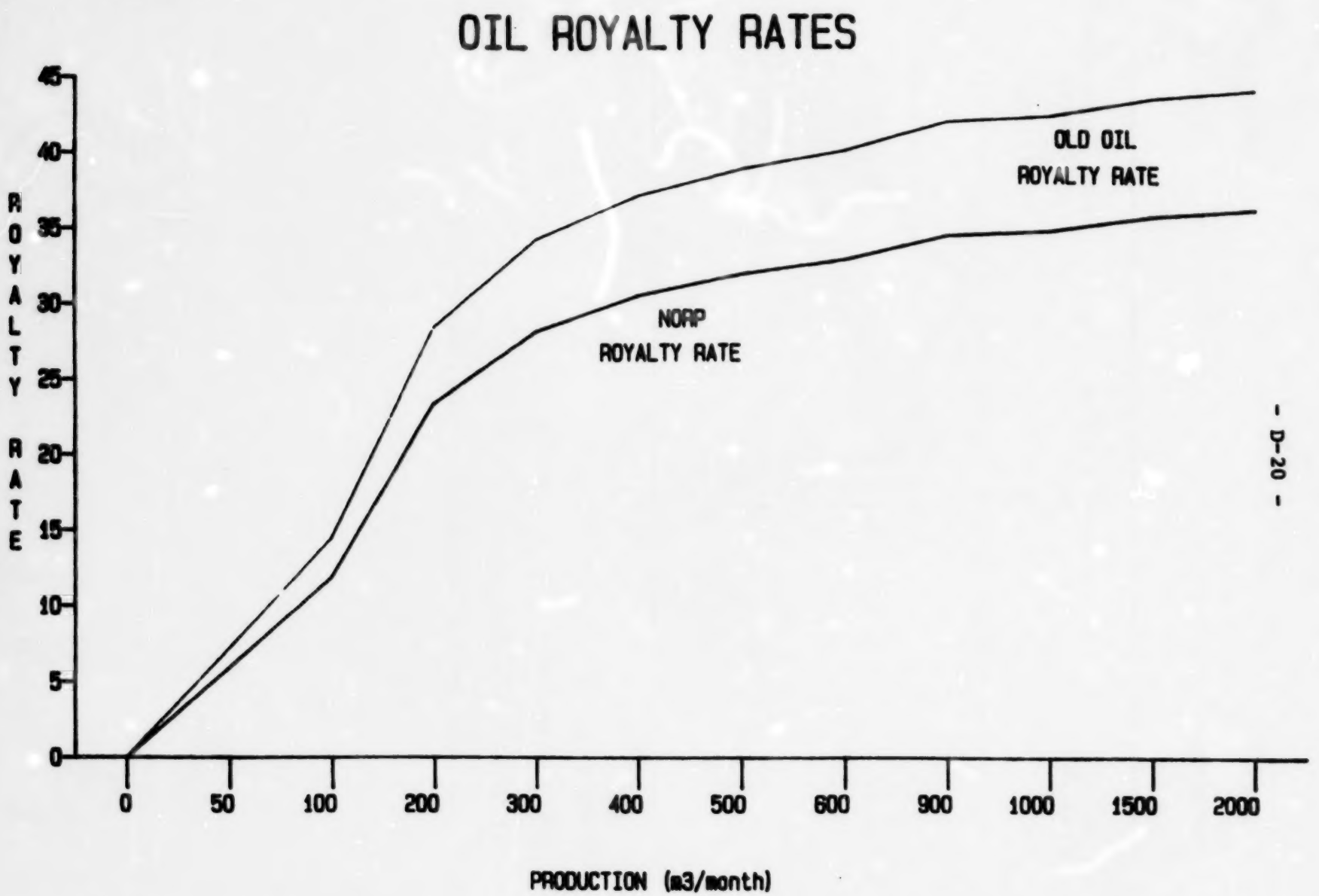

OIL ROYALTY RATES
ROYALTY RATE
45
40
35
30
25
20
15
10
5
0
OLD OIL
ROYALTY RATE
NORP
ROYALTY RATE
0
50
100
200
300
400
500
600
900
1000
1500
2000
PRODUCTION (m3/month)

Figure D2

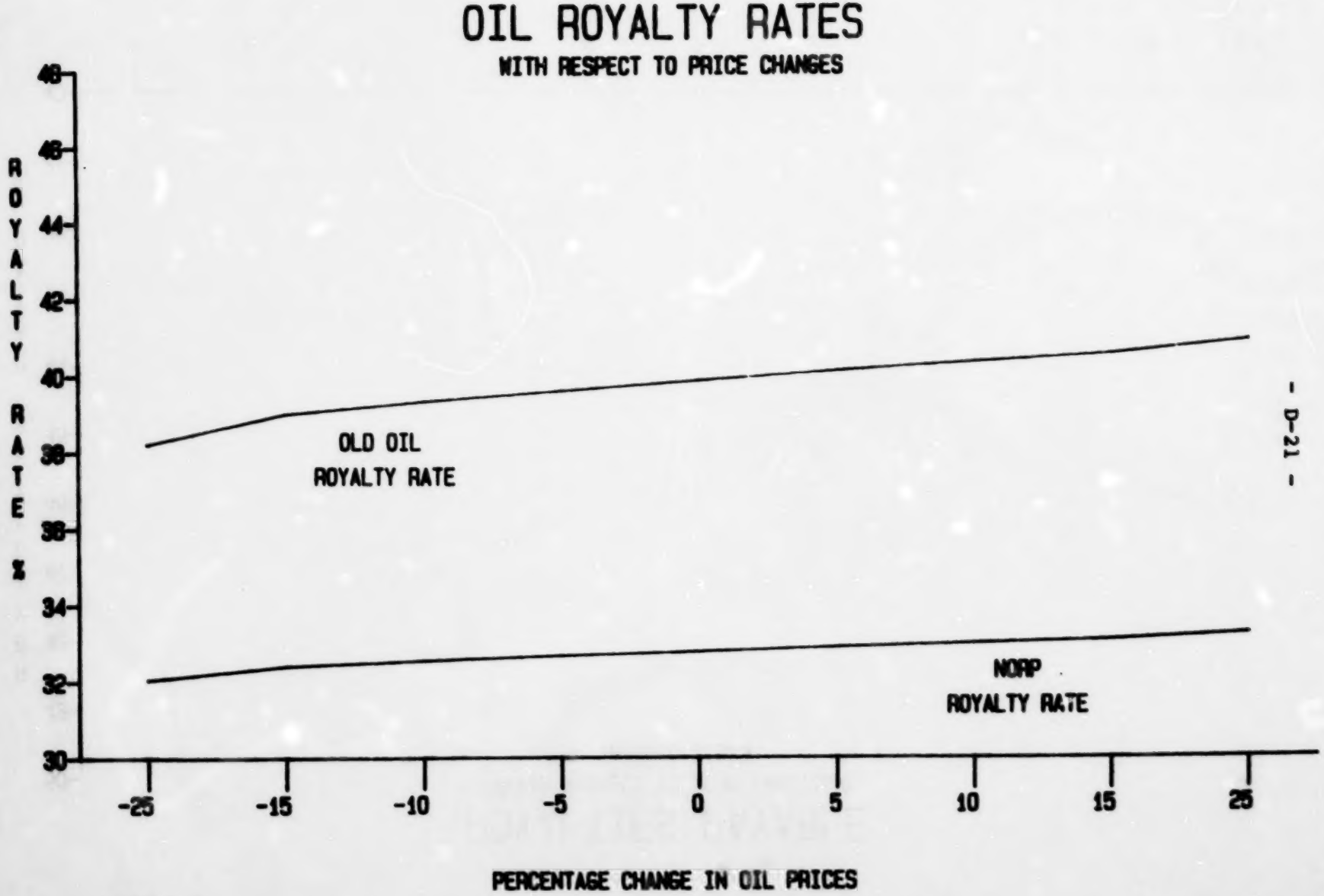
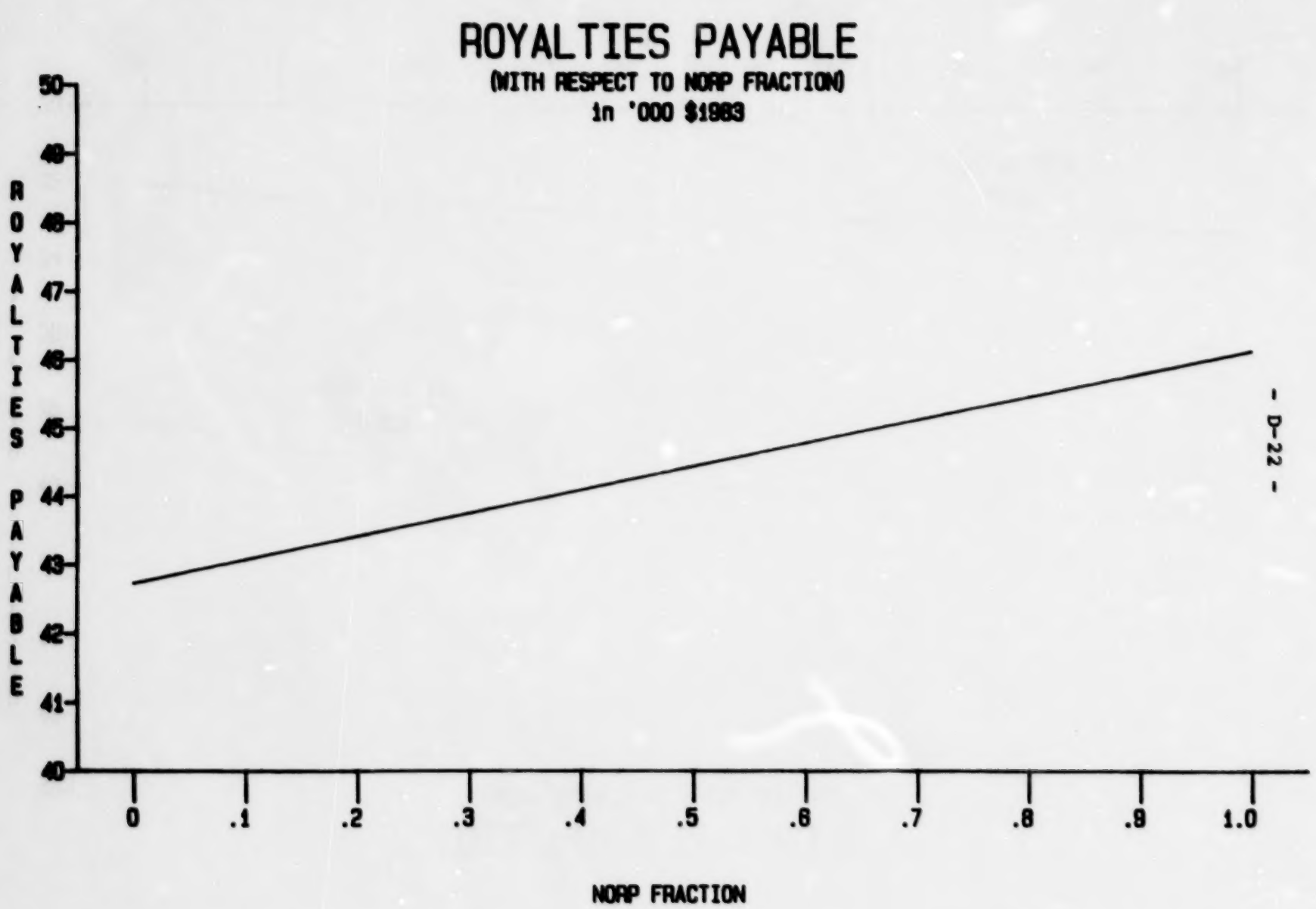

OIL ROYALTY RATES
WITH RESPECT TO PRICE CHANGES
ROYALTY RATE %
48
46
44
42
40
38
36
34
32
30
OLD OIL
ROYALTY RATE
NORP
ROYALTY RATE
-25
-15
-10
-5
0
5
10
15
25
PERCENTAGE CHANGE IN OIL PRICES

Figure D3


ROYALTIES PAYABLE
(WITH RESPECT TO NORP FRACTION)
in '000 $1983
ROYALTIES PAYABLE
50
49
48
47
46
45
44
43
42
41
40
0
.1
.2
.3
.4
.5
.6
.7
.8
.9
1.0
NORP FRACTION

Notes

1 The ammendments to Section 4.2 of the Petroleum Royalty Regulations were as outlined in a News Release from the Government of Alberta dated October 13, 1983.

2 The Guidelines for Allowable Costs are directly from Application Procedures - Petroleum Royalty Releif EOR Schemes, Alberta Energy and Natural Resources, Mineral Revenues, October 14, 1982.

3 Communique, Energy, Mines and Resources, May 19, 1983.

Notes

1 It should be noted that the "base case project" modelled for South Swan Hills includes the secondary miscible flood in the South Swan Hills Unit.

2 This is the method used to calculate the NORP fraction (a-factor) by the Alberta Department of Energy and Natural Resources (ENR).

3 Section 4.2, Alberta Petroleum Royalty Calculations, October 14, 1982.

4 The calculations reported in this paper do not include the NGL rebate. Furthermore, all injection fluids are treated as purchased fluids.

5 The information presented in Section 3.2 was obtained from Amoco's application to the AERCB for a miscible flood project in the West Waterflood area of the South Swan Hills Unit and the AERCB Annual Reserves Report, ERCB 82-18.

6 Memorandum of Agreement between the Government of Canada and the Government of Alberta relating to Energy Pricing and Taxation, September 1, 1981.

7 The information presented in Section 4.2 was obtained from Amoco's Application to the AERCB for a miscible flood project in Nipisi Gilwood Unit 1 as well as from the AERCB Annual Reserves Report, ERCB 82-18.

8 The information provided in Section 5.2 is from the AERCB Annual Reserves Report, ERCB 82-18 as well as information and data received from Amoco Canada Ltd.

POOR

QUALITY

ORIGINAL